North American Energy Standards Board

Executive Committee Meeting

Wholesale Electric Quadrant
Retail Gas Quadrant
Retail Electric Quadrant
Wholesale Gas Quadrant

November 29 – December 1, 2005

400 N. Capitol Street NW, Suite 450, Washington DC
Hosted by American Gas Association

NORTH AMERICAN ENERGY STANDARDS BOARD

Executive Committee Meeting – WEQ, REQ, RGQ, WGQ Meeting Materials
November 29 – December 1, 2005

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NORTH AMERICAN ENERGY STANDARDS BOARD

Executive Committee Meeting – WEQ, REQ, RGQ, WGQ Meeting Materials

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Wholesale Electric Quadrant

TAB 8

2005 Annual Plan for WEQ

- The 2005 plan as approved by the Board of Directors via the Managing Committee on September 22 is included. Should the WEQ EC determine that changes are to be made to the plan as a result of the subcommittee updates, a motion to approve the changes for forwarding to the Board for approval (September 22) would be required. The motion would require a simple majority to pass.
- The materials in Tab 6 correspond to agenda item 3 for the WEQ EC agenda.

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
2005 WEQ Annual Plan Approved by the NAESB Board of Directors on June 22, 2005
Revised by the WEQ EC on August 23, 2005

	Item Description	Completion[1]	Assignment
1	**Develop business practices standards as needed to complement reliability standards**		
	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:		Business Practices Subcommittee (BPS)
	a) Determine enhancements to "Version 0" business practices and/or new business practices as identified in the Version 0 development process.	High Priority	
	i) Catalogue and prioritize enhancements to "Version 0" business practices as identified in the Version 0 development process (i.e. meeting minutes) and comment periods.	High Priority 1st Q 2005	BPS
	Completed.		
	ii) Develop enhancements to "Version 0" business practices and/or develop new business practices as identified in the Version 0 development process (i.e. meeting minutes) and comment periods.	As Requested High Priority	Various
	Underway.		
	b) Make version 1 changes to business practices related to functional model entities as NERC undertakes the same efforts, (Interchange Authority, Reliability Authority, Transmission Service Provider and Purchasing-Selling Entity for Interchange Market Operator for Interchange).	Ongoing	BPS
	Not Started. Dependent on NERC actions.		
	c) Develop Inadvertent Interchange Payback Business Practices (2003 WEQ Annual Plan Item 6)	4th Q, 2005	BPS
	Underway.		
	d) Develop business practices to support Coordinate Interchange – update already adopted version 1 to reflect version 1 NERC CI (R03013, R05001)	4th Q, 2005 Low Priority	BPS
	Dependent on NERC activities.		
	e) Develop business practice standards to support Operate Within Limits (R03017)	2006	BPS
	Underway. Dependent on Action item 1(f).		
	f) Develop business practices to support the reliability components of TLR	4th Q, 2005	BPS
	Underway.		
	g) Determine any needed NAESB action in support of the Interchange Distribution Calculator (IDC).	2006	BPS
	Underway. Dependent on Action item 1(f).		
	h) Develop jointly with NERC a Joint NERC/NAESB Operating training manual.	2005	TBD

[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.

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NORTH AMERICAN ENERGY STANDARDS BOARD
2005 WEQ Annual Plan Approved by the NAESB Board of Directors on June 22, 2005
Revised by the WEQ EC on August 23, 2005

	Item Description	Completion[1]	Assignment
	Completed.	High Priority	
2	**Develop business practice standards for Version 1 to support ATC calculations**		
	a) Review Version 0 NERC reliability standards and comments regarding ATC calculations to determine if business practice standards are needed for NAESB Version 1.	1st Q, 2005	BPS
	Completed.		
	b) Develop version 1 business practice standards to better coordinate the use of the transmission system among neighboring transmission providers. Such business practice standards may be based on recommendations from NERC's Long Term ATC/AFC Task Force and could involve revised procedures for the ATC calculation and/or revised protocols for coordination between neighboring transmission providers and/or amendments to existing TLR procedures.	Ongoing	BPS
	Not Started. Awaiting revised clarified request R05004 from NERC.		
3	**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:	2005	Electronic Scheduling Subcommittee (ESS) and Information Technology Subcommittee (ITS)
	i. Ongoing maintenance and enhancement of OASIS Phase IA Business Practices and S&CP, including but not limited to:		
	1) Clarification of definitions and terminology in OASIS Business Practices	3rd Q, 2005	ESS/ITS
	Underway.		
	2) Business Practices for the resale or reassignment of transmission service (R04006D)	3rd Q, 2005	ESS/ITS
	Underway.		
	3) Implementation of "release" mechanism in the OASIS S&CP to complement non-firm redirects	3rd Q, 2005	ESS/ITS
	Underway.		
	4) Network Services: determine if business practice standards or other support is needed to support use of OASIS for Network Service transactions.	2006	ESS/ITS
	Underway.		
	5) Registry: determine if business practice standards are needed to support the registry functions currently supported by NERC.	2006	ESS/ITS
	Underway.		
	ii. OASIS Phase II per FERC ANOPR (Docket no. RM00-10-000) and subsequent orders:	2006	ESS/ITS

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NORTH AMERICAN ENERGY STANDARDS BOARD
2005 WEQ Annual Plan Approved by the NAESB Board of Directors on June 22, 2005
Revised by the WEQ EC on August 23, 2005

	Item Description	Completion[1]	Assignment
	1) Adoption/maintenance of ESC use cases (R04007) *Underway.*		
	2) Adoption/maintenance of Functional Requirements Document (R04007) *Underway.*		
	3) Develop and maintain business practices to support and implement the ESC use cases (R04007) *Underway.*		
	4) PKI Initiative (e-MARC) (R03007) *Underway.*		
b)	Develop and/or maintain standard communication protocols and cyber-security requirements as needed, including related industry standard communication protocols and cyber-security requirements	2006	ITS
	i. OASIS Phase II per FERC ANOPR (Docket no. RM00-10-000) and subsequent orders (R04007) *Underway as OASIA 1A enhancements.*		
	ii. Develop companion business practices to NERC's Cyber Standard (1300), and specifically review section 1303-Personnel & Training to determine if business practices are needed.		
c)	Develop business practices as needed for clarification of definitions and terminology in the Standards of Conduct. *Complete.*[2]	2nd Q, 2005	ESS/ITS
d)	Develop needed business practice standards for organization/company codes for NAESB standards – and address current issues on the use of DUNs numbers. *Underway.*	4th Q, 2005	DUNs Task Force
4	**Develop business practices standards to Improve the Current Operation of the wholesale electric market**		
a)	Evaluate the entries on the seams catalog, determine the need for business practice standards and draft the standards requests to develop business practice standards to complement or assist specific seams mitigation efforts as noted in the seams catalog. *None requested to date.*	As Requested	Various
b)	Develop business practice standards according to approved and assigned standards requests that complement or assist specific seams mitigation efforts as noted in the seams catalog. *None requested to date.*	As Requested	Various

[2] The changes to the Standards of Conduct requested by the Commission in NOPR RM05-5-000 will be made as soon as possible.

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NORTH AMERICAN ENERGY STANDARDS BOARD
2005 WEQ Annual Plan Approved by the NAESB Board of Directors on June 22, 2005
Revised by the WEQ EC on August 23, 2005

	Item Description	Completion[1]	Assignment
c)	Develop business practices to support Western Interconnection Tag Definitions (R04032) *Complete.*	Withdrawn	BPS
5	**Determine the need for and develop, if necessary, business practice standards supportive of the Gas-Electric Coordination Report**		
a)	Evaluate and develop business practice standards for Energy Day (R04016) *Postponed.*	Tabled based on Board Action on 06/22/05	BPS
b)	Evaluate and develop business practice standards for electric scheduling timelines (R04020). *Postponed.*	Tabled based on Board Action on 06/22/05	ESS
c)	Evaluate and develop business practice standards for communications between entities representing gas-fired power generators and the pipelines serving them (R04021) *Complete.*	2nd Q, 2005 High Priority	BPS

PROVISIONAL ITEMS

1 Develop business practice standards as requested by the regional and state advisory groups.

2 Using the NERC Interconnected Operations Services reference document (March 2002, version 1.1) as a guide and starting point, develop business practices as necessary for ancillary services and/or interconnected operating services transactions.

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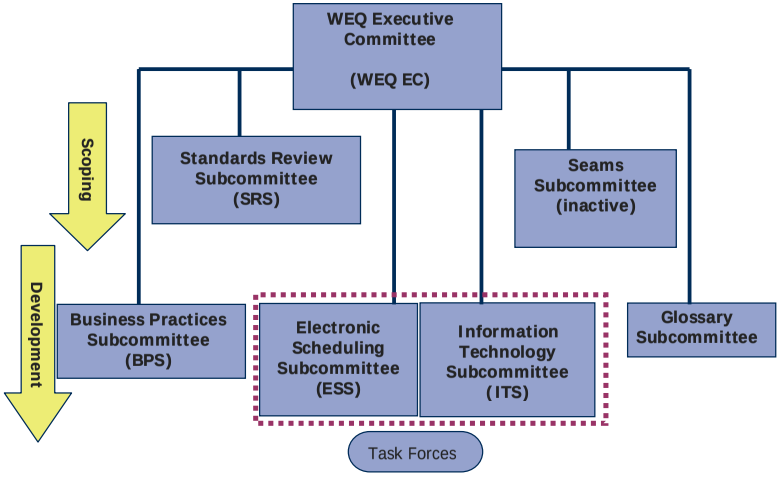
NAESB Wholesale Electric Quadrant Committee Structure



NAESB WEQ EC Subcommittee Leadership:

Executive Committee: Lou Oberski (WEQ EC Chair) and Tony Reed (WEQ EC Vice Chair)

Standards Review Subcommittee: Raj Rana, Narinder Saini, Ollie Frazier

Seams Subcommittee: Inactive

Business Practices Subcommittee & Task Forces: Kathy York

- TLR: Michael Desselle (inactive – now encompassed in BPS normal work)
- Inadvertent Interchange Payback: Phil Cox
- Energy Day: Kathy York (inactive – tasks complete)

Electronic Scheduling Subcommittee/Information Technology Subcommittee & Task Forces: Paul Sorenson, J.T. Wood and Sherri Monteith

- Coordinate Interchange: Roman Carter
- Joint Interchange Scheduling Working Group (JISWG): Bob Harshbarger
- OASIS 1A: J.T. Wood and Wendy Weathers
- OASIS 2: Paul Sorenson and Jagjit Singh (inactive – focus in OASIS 1A)

Glossary Subcommittee (to be renamed): Sherri Monteith

NORTH AMERICAN ENERGY STANDARDS BOARD

Executive Committee Meeting – WEQ, REQ, RGQ, WGQ Meeting Materials

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Wholesale Electric Quadrant

TAB 9

2006 Annual Plan for WEQ

- The 2006 plan as drafted by the WEQ leadership is included. The EC is expected to consider this plan and vote to approve. It would then be forwarded to the Board of directors for consideration and approval on December 13. The motion would require a simple majority to pass.
- The materials in Tab 9 correspond to agenda item 4 for the WEQ EC agenda.

North American Energy Standards Board
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Home Page: www.naesb.org

NORTH AMERICAN ENERGY STANDARDS BOARD
Draft 2006 WEQ Annual Plan as of 11-11-05

Item Description	Completion[1]	Assignment[2]
1 Develop business practices standards as needed to complement reliability standards		
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:		
a) Make version 1 changes to business practices as requested.	Ongoing	BPS
i) Make changes to business practices as related to inclusion of functional model entities as NERC undertakes the same efforts	As requested	BPS
ii) Review the NAESB WEQ "Version 0" business practice standards and remove any references to ERCOT (R05007)	1st Q, 2006	BPS
b) Develop Inadvertent Interchange Payback Business Practices (2003 WEQ Annual Plan Item 6)	1st Q, 2006	BPS
Note: Disposition of item 1b may change based on the Executive Committee meeting November 29, 2005.		
c) Develop business practices to support Coordinate Interchange – update already adopted version 1 to reflect version 1 NERC CI (R03013, R05001, R05020)	3rd Q, 2006	BPS
d) Develop business practice standards to support Operate Within Limits (R03017)	2006	BPS
e) Develop business practices to support the reliability components of TLR		
i) Version 0 Split of TLR business practices from reliability components	1st Q, 2006	BPS
Note: Disposition of item 1e (i) may change based on the Executive Committee meeting November 29, 2005		
ii) Continuous support of TLR Procedure in alignment with NERC efforts including version 1 development	Ongoing	BPS
f) Determine any needed NAESB action in support of the Interchange Distribution Calculator (IDC).	2006	BPS
g) Develop jointly with NERC a Joint NERC/NAESB Operating training manual.	2006	Not Assigned
2 Develop business practice standards for Version 1 to support ATC calculations		
Develop version 1 business practice standards to better coordinate the use of the transmission system among neighboring transmission providers. Such business practice standards would be based on recommendations from NERC's Long Term ATC/AFC Task Force and would involve revised procedures for the ATC calculation and/or revised protocols for coordination between neighboring transmission providers and/or amendments to existing TLR procedures.	Ongoing	BPS
Note: Awaiting revised clarified Request R05004 from NERC – to develop transmission service request and scheduling standards using TTC/ATC/AFC and CBM/TRM.		

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NORTH AMERICAN ENERGY STANDARDS BOARD
Draft 2006 WEQ Annual Plan as of 11-11-05

Item Description	Completion[1]	Assignment[2]
3 Develop business practices standards to improve the current operation of the wholesale electric market and 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. Specific items to address include:		
i) Clarification of definitions and terminology in OASIS Business Practices (R04035 and R05002)	1st Q, 2006	ESS/ITS
Note: Disposition of item 3a(i) may change based on the Executive Committee meeting November 29, 2005.		
ii) Business Practices for the resale or reassignment of transmission service (R04006D)	1st Q, 2006	ESS/ITS
Disposition of item 3a(ii) may change based on the Executive Committee meeting November 29, 2005.		
iii) Implementation of "release" mechanism in the OASIS S&CP to complement non-firm redirects (R04006C1)	1st Q, 2006	ESS/ITS
iv) Network Services: determine if business practice standards or other support is needed to support use of OASIS for Network Service transactions (R04006E).	3rd Q, 2006	JISWG
v) Registry: determine if business practice standards are needed to support the registry functions currently supported by NERC (R04037).	2nd Q, 2006	JISWG
vi) Adoption/maintenance of ESC use cases (R04007)	1st Q, 2006	ESS/ITS
vii) Adoption/maintenance of Functional Requirements Document (R04007)	1st Q, 2006	ESS/ITS
viii) PKI Initiative (e-MARC) (R03007)	1st Q, 2006	JISWG
ix) e-Tag enhancements (including e-Tag specification changes) (R05018)	2nd Q, 2006	ESS/ITS
x) Document procedures used to implement the displacement/interruption terms of the Pro Forma tariff (R05019)	3rd Q, 2006	ESS/ITS
xi) Incremental enhancements to OASIS as an outgrowth of the NAESB March 29, 2005 conference on the future of OASIS (R05026)	4th Q, 2006	ESS/ITS
b) Develop and/or maintain standard communication protocols and cyber-security business practices as needed		
i) Develop companion business practices to NERC's Cyber Standard (1300), and specifically review section 1303-Personnel & Training to determine if business practices are needed.	3rd Q, 2006	ESS/ITS
ii) Partner with the Department of Energy to perform a surety assessment on NAESB technical standards and respond to the surety assessment findings and recommendations.	4th Q, 2006	EC Officers

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NORTH AMERICAN ENERGY STANDARDS BOARD
Draft 2006 WEQ Annual Plan as of 11-11-05

	Item Description	Completion[1]	Assignment[2]
c)	Develop business practices as needed for clarification of definitions and terminology in the Standards of Conduct[3]	1st Q, 2006	BPS
d)	Develop needed business practice standards for organization/company codes for NAESB standards – and address current issues on the use of DUNs numbers.	4th Q, 2006	Not Assigned
4	**Develop and/or maintain business practice standards to support gas-electric interdependencies**		
a)	Respond to requests as received that are related to Docket No. RM05-28-000.	Dependent on requests received.	Not Assigned
b)	Respond directives related to the conclusions of the NAESB reports submitted in Docket No. RM05-28-000.	Dependent on requests received.	Not Assigned
c)	Evaluate and develop business practice standards for Energy Day (R04016)	Tabled[4]	BPS
d)	Evaluate and develop business practice standards for electric scheduling timelines (R04020).	Tabled[4]	ESS/ITS

PROVISIONAL ITEMS

1 Develop business practice standards as requested by the regional and state advisory groups.

2 Using the NERC Interconnected Operations Services reference document (March 2002, version 1.1) as a guide and starting point, develop business practices as necessary for ancillary services and/or interconnected operating services transactions.

3 Develop and or modify business practices related to OATT reform resulting from the Notice of Inquiry, Docket No. RM05-25-000, FERC Notice Requesting Comments, "Preventing Undue Discrimination and Preference in Transmission Services", issued September 16, 2005.

4 Evaluate the entries on the seams catalog, determine the need for business practice standards and draft the standards requests to develop business practice standards to complement or assist specific seams mitigation efforts as noted in the seams catalog.

5 Develop business practice standards according to approved and assigned standards requests that complement or assist specific seams mitigation efforts as noted in the seams catalog.

6 Develop business practice standards as related to the Effectiveness Study of Competitive Wholesale Markets (Congressional Mandate), Electric Energy Market Competition Task Force, Docket No. AD05-17-000, issued by the FERC on October 13, 2005.

7 Upon the issuance of the final order by FERC, develop and or modify business practices as requested by FERC related to OASIS or Version 0 business practices as filed by NAESB with the FERC on January 18, 2005, in Docket No. RM05-5-000. The FERC Notice of Proposed Rulemaking, RM05-5-000, "Standards for Business Practices and Communication Protocols for Public Utilities," was issued May 9, 2005.

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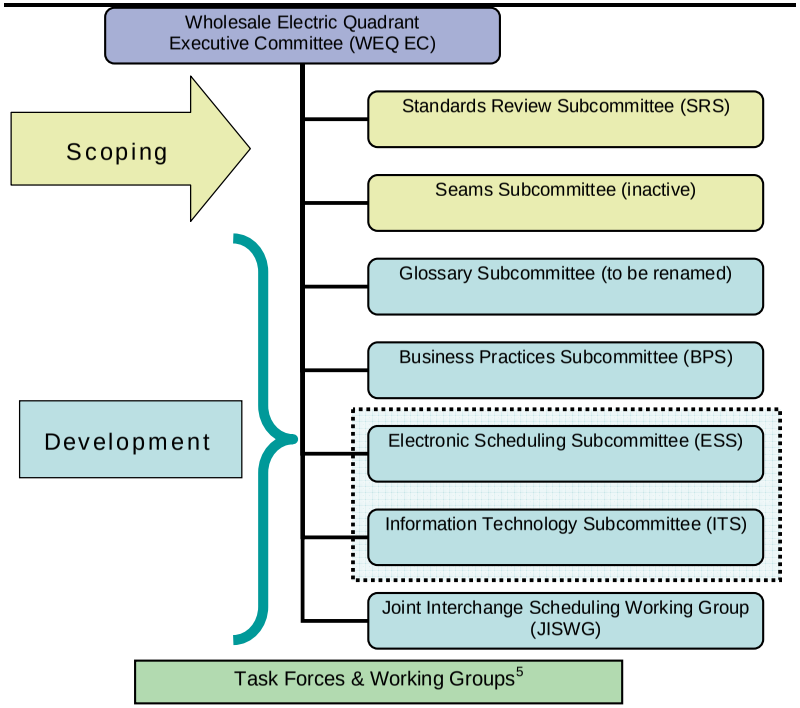

NAESB WEQ EC and Subcommittee Leadership:

Executive Committee: Lou Oberski (WEQ EC Chair) and Tony Reed (WEQ EC Vice Chair)

Standards Review Subcommittee: Raj Rana, Narinder Saini, Ollie Frazier

Seams Subcommittee: Inactive

Business Practices Subcommittee & Task Forces: Kathy York & Joel Dison

Electronic Scheduling Subcommittee/Information Technology Subcommittee & Task Forces: Paul Sorenson, J.T. Wood and Sherri Monteith

- Coordinate Interchange: Roman Carter
- OASIS: J.T. Wood and Wendy Weathers

Joint Interchange Scheduling Working Group (JISWG): Bob Harshbarger

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End Notes:

[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 assignments are abbreviated. The abbreviations and committee structure can be found at the end of the annual plan document.
[3] The changes to the Standards of Conduct requested by the Commission in NOPR Docket No. RM05-5-000 will be made as soon as possible.
[4] The Board of Directors determined to table items 4c and 4d at the June 22 ,2005 meeting. Depending on the outcome of the board meeting on December 13, 2005, both Request Nos. R04016 and R04020 may be withdrawn by the submitters.
[5] The WEQ EC and the subcommittees may create task forces, working groups and ad hoc groups to address specific topics within their scopes of effort.

NORTH AMERICAN ENERGY STANDARDS BOARD

Executive Committee Meeting – WEQ, REQ, RGQ, WGQ Meeting Materials

Wholesale Electric Quadrant

TAB 10

Recommendations for Vote – IIPTF Report

- Recommendation R05009 is attached. The comment period for this request ended November 14. Nine sets of comments were received.
- To approve the recommendation that would leave the IIP standards as is, a motion to accept the recommendation would be made by a WEQ EC member, and the resulting vote would need to be 67% of the WEQ EC members (20 of 29 members) and 40% of each segment's EC members.
- The materials in Tab 10 correspond to agenda item 5 for the WEQ EC agenda.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: WEQ Market Operations Subcommittee
Request No.: 2003 WEQ Annual Plan Item 6 - IIP
Request Title: Inadvertent Interchange Payback

Date Prepared: October 10, 2005

1. RECOMMENDED ACTION:

___Accept as requested
___Accept as modified below
_X_Decline

EFFECT OF EC VOTE TO ACCEPT RECOMMENDED ACTION:

___Change to Existing Practice
_X_Status Quo

2. TYPE OF DEVELOPMENT/MAINTENANCE

Per Request:	**Per Recommendation:**
_X_Initiation	___Initiation
___Modification	___Modification
___Interpretation	___Interpretation
___Withdrawal	___Withdrawal
___Principle	___Principle
___Definition	___Definition
_X_Business Practice Standard	___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:

The IIPTF reviewed numerous possible solutions to the settlement of Inadvertent Interchange and determined that, at this time, none of the proposed solutions are better than the NAESB Version 0 standard.

The attached final report discusses the history of the IIPTF and each of the proposed solutions it considered.

RECOMMENDED STANDARDS:

No new standards are recommended and no changes to or deletions of existing standards are recommended.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: WEQ Market Operations Subcommittee
Request No.: 2003 WEQ Annual Plan Item 6 - IIP
Request Title: Inadvertent Interchange Payback

Date Prepared: October 10, 2005

4. SUPPORTING DOCUMENTATION

a. Description of Request:

The Request for Standards proposed a standard to define the alternatives that may be used to settle Inadvertent Interchange while mitigating the potential financial gain that misuse of the current payback-in-kind methodology fails to prevent.

b. Description of Recommendation:

Over more than two years of deliberations, the IIPTF reviewed numerous possible solutions to the settlement of Inadvertent Interchange. Solutions studied by the IIPTF included: different variations of financial settlement with and without a frequency bandwidth, fixed, locational native and market-driven pricing; and an automatic time error correction solution currently in use in the Western Interconnection (WATEC). Each of the proposed solutions has one or more significant implementational hurdles to overcome, including but not limited to: data acquisition and integrity; pricing; credit; funding; 100% participation of the affected interconnection; and the task force's opinion that an ACE-driven solution, such as WATEC, should be developed in the NERC environment. For these reasons the task force determined that the NAESB Version 0 standard is appropraite in its current form.

c. Business Purpose:

If proposed standards were to be offered by the task force, they would reflect the alternatives that may be used to settle Inadvertent Interchange while mitigating the potential financial gain that misuse of the current payback-in-kind methodology fails to prevent. The task force determined that the standards included in Version 0 are sufficient and no changes are needed.

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

This request was worked on in the following meetings and conference calls:

Meeting/Conference Call	**Date**	**Link to Minutes:**
IIPTF Conference Call	02/13/2003	http://www.naesb.org/pdf/weq_iiptf021303dm.pdf
IIPTF Meeting	02/19/2003	http://www.naesb.org/pdf/weq_iiptf021903fm.pdf
IIPTF Conference Call	02/27/2003	http://www.naesb.org/pdf/weq_iiptf022703fm.pdf
IIPTF Conference Call	03/31/2003	http://www.naesb.org/pdf/weq_iiptf033103fm.pdf
IIPTF Meeting	04/09/2003	http://www.naesb.org/pdf/weq_iiptf040903fm.pdf
IIPTF Meeting	04/29/2003	http://www.naesb.org/pdf/weq_iiptf042903fm.pdf
IIPTF Meeting	05/08/2003	http://www.naesb.org/pdf/weq_iiptf050803fm.pdf
IIPTF Meeting	06/04/2003	http://www.naesb.org/pdf/weq_iiptf060403fm.pdf

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: WEQ Market Operations Subcommittee
Request No.: 2003 WEQ Annual Plan Item 6 - IIP
Request Title: Inadvertent Interchange Payback

Date Prepared: October 10, 2005

Meeting/Conference Call	Date	Link to Minutes:
IIPTF Conference Call	06/18/2003	http://www.naesb.org/pdf/weq_iiptf061803fm.pdf
IIPTF Meeting	07/09/2003	http://www.naesb.org/pdf/weq_iiptf070903fm.pdf
IIPTF Conference Call	07/23/2003	http://www.naesb.org/pdf/weq_iiptf072303fm.pdf
NERC/NAESB IIPTF Organizational Meeting	08/04/2003	http://www.naesb.org/pdf/weq_nn_iiptf080403rdm.pdf
IIPTF Meeting	08/06/2003	http://www.naesb.org/pdf/weq_iiptf080603fm.pdf
IIPTF Conference Call	08/20/2003	http://www.naesb.org/pdf/weq_iiptf082003fm.pdf
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IIPTF Meeting	04/01-02/2004	http://www.naesb.org/pdf/weq_iiptf040104fm.pdf
IIPTF Meeting	05/05-06/2004	http://www.naesb.org/pdf/weq_iiptf050504fm.doc
IIPTF Meeting	05/26-27/2004	http://www.naesb.org/pdf/weq_iiptf052604fm.doc
IIPTF Meeting	06/23-24/2004	http://www.naesb.org/pdf/weq_iiptf062304fm.doc
IIPTF Conference Call	07/01/2004	http://www.naesb.org/pdf/weq_iiptf070104fm.doc
IIPTF Conference Call	07/13/2004	http://www.naesb.org/pdf/weq_iiptf071304fm.doc
IIPTF Meeting	07/26-27/2004	http://www.naesb.org/pdf/weq_iiptf072604fm.doc
IIPTF Conference Call	08/13/2004	http://www.naesb.org/pdf/weq_iiptf081304fm.doc
IIPTF Meeting	08/25-26/2004	http://www.naesb.org/pdf/weq_iiptf082504fm.doc
IIPTF Meeting	09/22-23/2004	http://www.naesb.org/pdf/weq_iiptf092204fm.doc
IIPTF Meeting	10/19-20/2004	http://www.naesb.org/pdf/weq_iiptf101904fm.doc
IIPTF Meeting	11/03-04/2004	http://www.naesb.org/pdf/weq_iiptf110304fm.doc
IIPTF Meeting	12/07-08/2004	http://www.naesb.org/pdf/weq_iiptf120704fm.doc
IIPTF Meeting	01/19-20-2005	http://www.naesb.org/pdf2/weq_iiptf011905fm.doc
IIPTF Meeting	02/23-24/2005	http://www.naesb.org/pdf2/weq_iiptf022305fm.doc
IIPTF Meeting	04/12-13/2005	http://www.naesb.org/pdf2/weq_iiptf041205fm.doc

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: WEQ Market Operations Subcommittee
Request No.: 2003 WEQ Annual Plan Item 6 - IIP
Request Title: Inadvertent Interchange Payback

Date Prepared: October 10, 2005

Meeting/Conference Call	Date	Link to Minutes:
IIPTF Conference Call	05/05/2005	http://www.naesb.org/pdf2/weq_iiptf050505fm.doc
IIPTF Conference Call	07/07/2005	http://www.naesb.org/pdf2/weq_iiptf070705fm.doc
IIPTF Conference Call	07/21/2005	http://www.naesb.org/pdf2/weq_iiptf072105fm.doc
IIPTF Conference Call	08/04/2005	http://www.naesb.org/pdf2/weq_iiptf080405dm.doc
IIPTF Conference Call	08/19/2005	http://www.naesb.org/pdf2/weq_iiptf081905dm.doc

The following votes were taken on the recommendation and final report:

At the April 12-13, 2005 IIPTF Meeting:

Mr. Reed moved, seconded by Mr. Henery, that the IIPTF accept the context of the statements above [shown below in italics] and meet by conference call on May 5, 2005 from 10:00 a.m. to noon Central to review a final version of the recommendation that will be reported to the May 10 Executive Committee meeting.

> *[Summary] The IIPTF reviewed numerous possible solutions to the settlement of Inadvertent Interchange and determined that, at this time, none of the proposed solutions are better than the NAESB Version 0 standard.*
>
> *[Description of Recommendation] Over more than two years of deliberations, the IIPTF reviewed numerous possible solutions to the settlement of Inadvertent Interchange. Solutions studied by the IIPTF included: different variations of financial settlement with and without a frequency bandwidth, fixed, locational native and market-driven pricing; and an automatic time error correction solution currently in use in the Western Interconnection (WATEC). Each of the proposed solutions has one or more significant implementational hurdles to overcome, including but not limited to: data acquisition and integrity; pricing; credit; funding; 100% participation of the affected interconnection; and the task force's opinion that an ACE-driven solution, such as WATEC, should be developed in the NERC environment. For these reasons the task force determined that the NAESB Version 0 standard is appropriate in its current form.*

The motion passed with five votes in favor, one opposed.

At the August 19, 2005 IIPTF Conference Call:

Mr. Henery moved, seconded by Mr. Carter, to accept the draft report as modified during the meeting.

The motion passed unanimously. Five IIPTF participants were in attendance.

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1301 Fannin, Suite 2350, Houston, Texas 77002
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: naesb@naesb.org
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via email and posting

TO: NAESB Wholesale Electric Quadrant Executive Committee, WEQ Members and Posting for Interested Parties

FROM: NAESB Inadvertent Interchange Payback Task Force

RE: IIPTF Report Discussing Task Force Results

DATE: October 11, 2005

This is the final report of the Inadvertent Interchange Payback Task Force (IIPTF) to advise the Wholesale Electric Quadrant (WEQ) Executive Committee that the task force has determined the NAESB Version 0 Inadvertent Interchange Payback Standard is an appropriate solution for the settlement of inadvertent interchange and request that the task force be disbanded.

History

The IIPTF was established in March 2003 to develop standards to define the alternatives that may be used to settle Inadvertent Interchange, consistent with 2003 WEQ Annual Plan Item 5. As noted in the standards request, the inadvertent interchange settlement standards would mitigate the potential financial gain that misuse of the payback-in-kind methodology allows. The request for standards suggested that the development of the standards would provide benefit to the industry because it would incent good behavior of balancing actual output and scheduled output within a reliable average limit and reduce the possibility of inadvertent accumulation. The IIPTF worked diligently over the course of 27 months, and considered five core proposals.

Accomplishments & Deliverables

The IIPTF has reviewed many different proposals for the settlement of Inadvertent Interchange and determined that the NAESB Version 0 Inadvertent Interchange Payback Standard is an adequate solution given the current NERC and regulatory environment. Although the task force did not develop a new standard, it did develop the following ancillary deliverables:

1) a library of published work papers discussing each of the settlement proposals[1];
2) increased industry awareness of potential settlement solutions through timely reports to the WEQ Executive Committee[2]; and
3) further analysis of the energy price component identified in NERC Joint Inadvertent Interchange Task Force (JIITF) Whitepaper
4) a way to coordinate/schedule payback under the Western Interconnection's Automatic Time-Error Cooorection (WATEC) in order to reconcile WATEC with the NERC ACE equation without modifying WATEC payback actions.

[1] All of the IIPTF work papers are available for public download from the NAESB website at http://www.naesb.org/weq/weq_iiptf.asp.
[2] The IIPTF's reports to the WEQ Executive Committee are available as part of the WEQ Executive Committee minutes from March 2003 to August 2005.

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Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: naesb@naesb.org
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Process & Procedures

The IIPTF has met a total of 41 times over 58 days[3]. The IIPTF used the work of the NERC JIITF as the initial model for development of the standards.

Although the task force used the JIITF Whitepaper as a starting point for development, the task force also explored alternatives to those solutions contained in the whitepaper. During its deliberations, the IIPTF discussed the following proposals:

- Financial Settlement of a Frequency Control Component
- Native Market Pricing of an Energy Component including a Transmission Congestion Component
- Wide Open Load Following (WOLF)
- Western Electricity Coordinating Council (WECC) Automatic Time Error Control (WATEC) (Option 2)
- Option 1
- NAESB Version 0 Inadvertent Interchange Payback Standard

Financial Settlement of a Frequency Control Component: Balancing Authorities' monthly average contribution to frequency error, in terms of their Inadvertent Interchange per Hertz of frequency deviation, would be assessed for purposes of monthly settlement. Those contributions settle exactly across the interconnection, between the BAs who were the net contributors to frequency error, and the BAs who were the net offsetters of frequency error. The settlement price (per megawatt) of inadvertent interchange for its contribution to frequency is some fixed-value times frequency error. This settlement price is the best estimate of what a market price for Inadvertent would be in an eventual market for trading NERC Control Performance Standard deviation allowances. Developed by the NERC JIITF and proposed by Mr. Illian and Mr. Blohm.

Many IIPTF participants did not feel comfortable with a "multipart" price or with settlement of frequency contribution separate from energy. "Option 1" below was an attempt to roll this into a "single" price for settlement of frequency contribution and energy (including transmission congestion) combined. Several IIPTF participants did not feel comfortable with a megawatt-per-hertz measure of FCC because as originally presented its price would rise exponentially with frequency deviation. The price per megawatt of FCC was later shown to rise linearly with frequency deviation, but this did not alleviate the pricing and implementability concerns on the part of several IIPTF members.

Native Market Pricing of an Energy Component including a Transmission Congestion Component: All North American ISOs, RTOs and FERC have concluded that transmission constraints result in market prices for energy that are different from market location to market location and have used centralized calculations to discover these price differences and provide them for market settlement. Native Market Pricing would provide equivalent pricing for areas that do not use a centralized calculation to derive these local market prices. Native Market Pricing instead depends upon the independent Native Market to derive the correct price through arbitrage, and then uses that Native Market Price in the settlement. The price for the energy would be the local spot market price or be the cost basis for the local schedule-4 tariff.

[3] A listing of meetings and conference calls is provided in Appendix 1 to this report.

This would include any price/cost differences attributable to congestion. Since this kind of pricing could result in either over or under collected revenues for an interconnection, a balancing algorithm was developed to assure balance settlement. This algorithm was based upon the amount of inadvertent contributed by each Native Market and it was demonstrated that using this balancing algorithm would maintain the marginal price differences necessary to properly represent the price differences due to the transmission constraints. Unfortunately, Native Market Pricing alone lacks any frequency control incentive, and therefore, is viable only when combined with an incentive mechanism such as the Frequency Control Component. When the Frequency Control Component was eliminated from consideration, Native Market Pricing was also doomed because of the loss of the correct incentive to provide good frequency control. Proposed by Mr. Illian and Mr. Blohm.

Some IIPTF participants did not like the need for an entity to manage the likely periodic overcollection for the energy that results from different local energy prices, and to redistribute pro-rata the overcollection, and the credit issues involved. Several IIPTF members took issue with default risk of financial settlement. Several IIPTF members observed that the actor hurting frequency is paying his own energy price, which incents bad frequency control while attempting to assure good congestion management.

Wide Open Load Following (WOLF) Proposal: WOLF sets real time prices for unscheduled flows of electricity using a formula (driven by frequency error) to modify a base energy price to reflect reliability concerns. WOLF uses a formula that escalates exponentially with frequency error. The reliability constants are the frequency deviations associated with a ten-fold change in price. WOLF uses a similar formula to modulate the base energy price for time error and cumulative time error, thus reflecting changes in basic fuel costs while eliminating the time error. WOLF prices can be geographically differentiated to reflect transmission constraints and line losses.

Many IIPTF participants did not feel comfortable with WOLF for not allowing negative prices. There was also concern about high price escalation and lack of coordination between the scheduled energy market price and WOLF pricing.

Western Electricity Coordinating Council (WECC) Automatic Time Error Control (WATEC) (Option 2) Proposal: The WATEC methodology is based on the principle that when a Balancing Authority experiences some type of operational problem that prevents its net scheduled interchange from matching its net actual interchange the prevailing Interconnection's system frequency changes. The other Balancing Authorities in the Interconnection will respond to correct the system frequency through their individual frequency bias term in their ACE equation.

The Balancing Authority causing the frequency error is said to have created "primary time error". The other Balancing Authorities in the Interconnection responding to correct system frequency are said to have created "secondary time error".

Time error is directly related to inadvertent interchange. All Balancing Authorities have procedures in place to determine their hourly inadvertent interchange. Converting hourly inadvertent interchange into "primary inadvertent interchange" a Balancing Authority can observe just that portion of the Interconnection's time error that they alone caused.

When all Balancing Authorities feedback this portion of "primary inadvertent interchange" into their ACE equation they continuously correct for just their own errors. The detailed derivation

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Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: naesb@naesb.org
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and explanation of the WECC ACE Equation used for control and inadvertent interchange payback are located on the WECC website www.wecc.biz.WATEC was supported by Mr. Henery.

Some IIPTF participants found WATEC to trade off adding new frequency error by timely unilateral payback, against economic fairness. While WATEC was found to eliminate much of the accumulation of Inadvertent Interchange allowed by the current Version 0 Standard, it was also found to allow for the same immediate economic advantage-taking as the current Version 0 Payback Standard. WATEC requires 100 percent participation and there were questions on whether 100 percent participation would be achievable in the East.

Option 1 Proposal: The proposed Option 1 Inadvertent Interchange Settlement Business Practice is modeled after the East Central Area Reliability Council (ECAR) Inadvertent Settlement Tariff. Option 1 uses a Frequency Bandwidth as an indicative measure where Inadvertent accumulated when the hourly average frequency is OUTSIDE the bandwidth, the settlement of the Inadvertent is financial. When Inadvertent is accumulated when the hourly average frequency is within the Frequency Bandwidth, the settlement of the Inadvertent is in kind (as it is settled today). The proposed Frequency Bandwidth is +/- 20 mHz around scheduled frequency (typically 59.98 mHz to 60.02 mHz). The proposed financial component, paid to the entity responding appropriately, is the greater of $100.00 per MWh or provable Market Price of the entity responding appropriately. In addition, the proposal allows for the entity responding appropriately to recover costs associated with taking generation offline in response to a HIGH frequency situation. Option 1 was proposed by Mr. Cox, Mr. Reed and Mr. Goss.

Some IIPTF members found that practically all Inadvertent Interchange would fall within the deadband contained in this option where settlement is no different than the current Version 0 Inadvertent Interchange Payback Standard. For the small amount of extreme Inadvertent Interchange lying outside the deadband, this option could have an unintended negative impact on reliability by causing upward drift of scheduled frequency, and violate the congestion-cost management requirement embedded in FERC tariffs.

NAESB Version 0 Inadvertent Interchange Payback Standard: The default status quo that carries forward portions of the old NERC Policy 1F related to the settlement of accumulated Inadvertent. The Version 0 Business Practice defines the Payback in Kind structure where, Inadvertent accumulated during On-Peak hours, must be paid back during On-Peak hours. Inadvertent accumulated during Off-Peak hours must be paid back during Off-Peak hours. The Version 0 Business Practice also allows for other methods of settlement of Inadvertent as agreed to by all members of the Interconnect.

Some IIPTF members opposed the Version 0 standard because modern market pricing is much more granular than on-peak and off-peak and therefore continues to allow economic abuse. Furthermore, the lack of a payback time-frame retains the incentive to accumulate Inadvertent Interchange accounts in order sometimes to avoid the uncompensated cost of fulfilling control obligations.

Conclusion

IIPTF participants recognize that significant effort was expended by NAESB and its member organizations to develop an Inadvertent Interchange settlement standard that would mitigate the potential financial gain that misuse of the payback-in-kind methodology does not prevent. However, a majority of the task force members determined that, at this time, none of the proposed solutions considered by the task force is better than the payback-in-kind

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Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: naesb@naesb.org
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methodology for the Eastern Interconnect (as embodied in the NAESB Version 0 Inadvertent Interchange Payback Standard.) Each of the proposed solutions considered has one or more significant implementation hurdles to overcome, including but not limited to: data acquisition and integrity; pricing; credit; funding; 100% participation of the affected interconnection; and the task force's opinion that because WATEC uses strictly reliability parameters, it should be developed in the NERC reliability environment.

The Inadvertent Interchange Payback "WATEC Option" and the "Option 1" were presented to the industry for consideration, to determine a preference, and to generate comments. The industry posting generated minimal responses which did not support either option. With the lack of industry direction for a new "inadvertent interchange payback" standard the IIPTF has inferred that the industry is satisfied with the requirements within the current NAESB Version 0 Inadvertent Interchange Business Practice Standard.

Supporting Documentation

Appendix I:	List of IIPTF Meetings
Appendix II:	Frequency Control Component
Appendix III:	Local Native Pricing
Appendix IV:	WOLF
Appendix V.	WATEC (Option 2)
Appendix VI:	Option 1
Appendix VII:	NAESB Version 0 Inadvertent Interchange Payback Standard
Appendix VIII:	Summary of Industry Posting for Comment of "WATEC Option" and "Option 1"

Appendix I: List of IIPTF Meetings

This appendix contains a list of IIPTF meetings and conference calls where 2003 WEQ Annual Plan Item 6 - IIP was discussed. Links to the individual meeting minutes and any workpapers discussed during the meetings are available on the NAESB website at http://www.naesb.org/WEQ/weq_iiptf.asp.

Date	Event/Location
August 19, 2005	Conference Call with Web Conferencing
August 4, 2005	Conference Call with Web Conferencing
July 21, 2005	Conference Call with Web Conferencing
July 7, 2005	Conference Call with Web Conferencing
May 5, 2005	Conference Call with Web Conferencing
April 12-13, 2005	Meeting held in Houston, TX hosted by NAESB (with Web Conferencing)
February 23-24, 2005	Meeting held in Houston, TX hosted by NAESB (with Web Conferencing)
January 19-20, 2005	Meeting held in Houston, TX hosted by NAESB (with Web Conferencing)
December 7-8, 2004	Meeting held in Houston, TX hosted by NAESB (with Web Conferencing)
November 3-4, 2004	Meeting held in Houston, TX hosted by NAESB (with Web Conferencing)
October 19-20, 2004	Meeting held in Houston, TX hosted by NAESB (with Web Conferencing)
September 22-23, 2004	Meeting held in Houston, TX hosted by NAESB (with Web Conferencing)
August 25-26, 2004	Meeting held in Colorado Springs, CO hosted by El Paso Corporation
August 13, 2004	Conference Call with Web Conferencing
July 26-27, 2004	Meeting held in Las Vegas, NV hosted by NAESB
July 13, 2004	Conference Call
July 1, 2004	Conference Call
June 23-24, 2004	Meeting held in Houston, TX hosted by NAESB
May 26-27, 2004	Meeting held in Houston, TX hosted by NAESB
May 5-6, 2004	Meeting held in Juno Beach, FL hosted by Florida Power & Light
April 1-2, 2004	Meeting held in Houston, TX hosted by NAESB
February 26-27, 2004	Meeting held in Houston, TX hosted by NAESB
January 22-23, 2004	Meeting held in Dallas, TX hosted by American Electric Power
December 10-11, 2003	Meeting held in Houston, TX hosted by NAESB
November 3, 2003	Meeting held in Houston, TX hosted by NAESB
October 6, 2003	Meeting held in Tempe, AZ hosted by NAESB
September 15-16, 2003	Meeting held in Austin, TX hosted by NAESB
August 20, 2003	Conference Call
August 6, 2003	Meeting held in Philadelphia, PA hosted by PECO
August 4, 2003	NERC/NAESB IIPTF Organizational Meeting held in Philadelphia, PA
July 23, 2003	Conference Call
July 9, 2003	Meeting held in Colorado Springs, CO hosted by El Paso Western Pipelines
June 18, 2003	Conference Call
June 4, 2003	Meeting held in Washington, DC hosted by EEI
May 8, 2003	Meeting held in Houston, TX hosted by NAESB
April 29, 2003	Meeting held in Houston, TX hosted by NAESB
April 9, 2003	Meeting held in Ft. Lauderdale, FL hosted by Florida Power & Light
March 31, 2003	Conference Call
February 27, 2003	Conference Call
February 19, 2003	Meeting held in New Orleans, LA hosted by NAESB
February 13, 2003	Conference Call

Appendix II: Frequency Control Component Proposal

This appendix contains a list of links to documents discussing the Frequency Control Component Proposal. Additional information on the proposal is available in the subcommittee minutes from the meetings where this proposal was discussed and the work papers associated with those meetings. All of the documents are available on the NAESB website at http://www.naesb.org/WEQ/weq_iiptf.asp.

Frequency Control Component Proposal Links:

Recommendations for the Wholesale Electric Industry of North America: *Inadvertent Interchange*, Draft 5d, May 10, 2002. A White Paper Prepared by the NERC Joint Inadvertent Interchange Task Force

http://www.naesb.org/pdf/weq_mos012403w5.pdf

Defining Good and Bad Inadvertent, presented by Mr. H. Illian

http://www.naesb.org/pdf/weq_iiptf021903w1.pdf

Public Utilities Fortnightly Article, authored by Mr. R. Blohm

http://www.naesb.org/pdf/weq_iiptf102704w7.pdf

Appendix III: Local Native Pricing Proposal

This appendix contains a list of links to documents discussing the Local Native Proposal. Additional information on the proposal is available in the subcommittee minutes from the meetings where this proposal was discussed and the work papers associated with those meetings. All of the documents are available on the NAESB website at http://www.naesb.org/WEQ/weq_iiptf.asp.

Local Native Pricing Proposal Links:

Recommendations for the Wholesale Electric Industry of North America: *Inadvertent Interchange,* Draft 5d, May 10, 2002. A White Paper Prepared by the NERC Joint Inadvertent Interchange Task Force

http://www.naesb.org/pdf/weq_mos012403w5.pdf

Native-Market-Pricing for Inadvertent Interchange, presented by Mr. H. Illian

http://www.naesb.org/pdf/weq_iiptf040104w6.pdf

Matrix of Outcomes for 5 Different Ways of Settling the Energy Component of Inadvertent Interchange, presented by Mr. R. Blohm

http://www.naesb.org/pdf/weq_iiptf012204w7.pdf

Assuring Balanced Settlement for Inadvertent Interchange, presented by Mr. H. Illian

http://www.naesb.org/pdf/weq_iiptf062304w2.doc

Marginal Energy Settlement of Inadvertent Interchange Using Native Prices, presented by Mr. H. Illian and Mr. R. Blohm

http://www.naesb.org/pdf/weq_iiptf062304w3.doc

Appendix IV: Wide Open Load Following Proposal

This appendix contains a list of links to documents discussing the Wide Open Load Following Proposal. Additional information on the proposal is available in the subcommittee minutes from the meetings where this proposal was discussed and the work papers associated with those meetings. All of the documents are available on the NAESB website at http://www.naesb.org/WEQ/weq_iiptf.asp.

Wide Open Load Following (WOLF) Proposal Links:

WOLF Pricing, presented by Mr. M. Lively
http://www.naesb.org/pdf/weq_iiptf121003w3.pdf

Appendix V: Western Electricity Coordinating Council Automatic Time Error Control Proposal

This appendix contains a list of links to documents discussing the Western Electricity Coordinating Council Automatic Time Error Control (WATEC) Proposal. Additional information on the proposal is available in the subcommittee minutes from the meetings where this proposal was discussed and the work papers associated with those meetings. All of the documents are available on the NAESB website at http://www.naesb.org/WEQ/weq_iiptf.asp.

Western Electricity Coordinating Council Automatic Time Error Control (WATEC) Proposal Links:

WECC Procedure for Time Error Control, submitted by Mr. N. Henery

http://www.naesb.org/pdf/weq_iiptf050504w2.pdf

Automatic Time Error Control presentation, presented by Mr. N. Henery

http://www.naesb.org/pdf/weq_iiptf072604w5.ppt

Conforming WECC Auto Time Error Correction to CPS1, presented by Mr. H. Illian

http://www.naesb.org/pdf/weq_iiptf102704w4.doc

Practical Meaning of Conforming WECC Auto Time Error Correction to CPS1, presented by Mr. R. Blohm

http://www.naesb.org/pdf/weq_iiptf101904w4.doc

Draft IIPTF Standard (Option 2), distributed for informal industry comment on December 10, 2004

http://www.naesb.org/pdf/weq_iiptf121004w3.doc

Appendix VI: Option 1 Proposal

This appendix contains a list of links to documents discussing the Option 1 Proposal. Additional information on the proposal is available in the subcommittee minutes from the meetings where this proposal was discussed and the work papers associated with those meetings. All of the documents are available on the NAESB website at http://www.naesb.org/WEQ/weq_iiptf.asp.

Option 1 Proposal Links:

Discussion Paper, presented by Mr. Reed

http://www.naesb.org/pdf/weq_iiptf012204w10.pdf

Draft IIPTF Standard (Option 1), distributed for informal industry comment on December 10, 2004

http://www.naesb.org/pdf/weq_iiptf121004w1.doc

Appendix VII: NAESB Version 0 Inadvertent Interchange Payback Standard

This appendix contains a link to the NAESB Version 0 Inadvertent Interchange Payback Standard.

NAESB Version 0 Inadvertent Interchange Payback Standard Links:

NAESB WEQ Inadvertent Interchange Payback Standards - WEQBPS – 005-000, January 15, 2005

http://www.naesb.org/pdf2/weq_bklet_011505_iip_mc.pdf

Appendix VIII: Summary of Industry Posting for Comment of "WATEC Option" and "Option 1"

This appendix contains a list of links to documents discussing the Industry Posting for Comment of "WATEC Option" and "Option 1", including the IIPTF's response to the industry comments. Additional information on the comments is available in the subcommittee minutes from the meetings where the comments were discussed and the work papers associated with those meetings. All of the documents are available on the NAESB website at http://www.naesb.org/WEQ/weq_iiptf.asp.

Summary of Industry Posting for Comment of "WATEC Option" and "Option 1" Links:

Request for Comments on Inadvertent Interchange Settlement "Version 1" Business Practices, distributed December 10, 2004

http://www.naesb.org/pdf/weq_iiptf121004w5.doc

Draft IIPTF Standard (Option 1), distributed for informal industry comment on December 10, 2004

http://www.naesb.org/pdf/weq_iiptf121004w1.doc

Draft IIPTF Standard (Option 2), distributed for informal industry comment on December 10, 2004

http://www.naesb.org/pdf/weq_iiptf121004w3.doc

IIPTF Response to Comments Submitted on IIPTF Option 1

http://www.naesb.org/pdf2/weq_iiptf121004a1.doc

IIPTF Response to Comments Submitted on IIPTF Option 2

http://www.naesb.org/pdf2/weq_iiptf121004a2.doc

From: Halpin,Francis J - PGS
Sent: Thursday, November 10, 2005 6:06 PM
To: NAESB
Subject: Comments on IIPTF recommendations

The Bonneville Power Administration (BPA) supports the recommendation of the IIPTF to leave the current process of Inadvertent Interchange (II) payback as it exists in NAESB version 0.

BPA is confident that the Task Force did a thorough job investigating the options for a new, improved business practice. BPA believes that the Task Force investigated all options and proposals presented to it, in a fair manner and with an open mind. It considered an wide range of proposals for methods of payback which addressed areas of concern and problems inherent in the current method. It weighed benefits of each of the methods weighed against the current methodology. The Task Force documented the thirty month process in such a manner that the NAESB web site now contains a vast body of information on the process of, and issues with, payback of Inadvertent Interchange.

BPA was pleased that the Task Force saw fit to include, in the draft standard, the WECC Automatic Time Error Control (ATEC) process as an acceptable method of payback. This process works very well for the Western Interconnection.

In the final analysis, the opinion of the Task Force was that none of the investigated methods represented a practicable replacement process for the current method of payback spelled out in version 0. BPA agrees with this conclusion.

BPA also agrees with the IIPTF conclusion that "*WATEC uses strictly reliability parameters, it should be developed in the NERC reliability environment* ." The WATEC algorithm runs on utility Energy Management Systems, which are the basis for reliable system operations. BPA is of the opinion that this fact separates the WECC method from other methods of payback and, indeed, makes it more of a reliability issue than one of pure business practice in the Western Interconnection.

If this Task Force recommendation is not accepted, BPA would like to see an extensive investigation into actual cases of misuse and gaming of the current system prior to re-embarking on an effort to further develop a new business practice for II payback. If the review reveals that cases of misuse are actually limited to a relatively few isolated incidents then further effort in this area may not be warranted. It the review shows the misuse to be more prevalent, but perhaps limited to relatively few companies, then stricter enforcement of current standards and strong sanctions for those are found to be misusing the current process may be more cost effective than attempting to rewrite the standard itself.

If NAESB decides reject the recommendation of the IIPTF and go forward with the development of a new standard, BPA would hope that the work of the IIPTF to date be used as the starting point for the continued work. Of particular interest for BPA would be the inclusion of the WECC ATEC method in the final standard. BPA believes that the ATEC method actually does address some of the concerns with the other current methods. ATEC requires payback to begin shortly after a system recovers from the contingency which caused it to accumulate Inadvertent in the first place. This requirement places the payback close in time to the accumulation. Although it doesn't provide a perfect price correlation, this method does takes payback discretion away from the accumulator and, given the volatility of the real time market and lack of perfect knowledge about future prices, one could never be certain what the price on the payback hour would be in relation to the hour of accumulation thus removing (or reducing) one of the motives for gaming since one could not "pick" a return hour with a favorable price delta.

In conclusion, BPA supports the IIPTF recommendation to retain the current process described in version 0 and to disband the Task Force.

BPA would also like to commend the Task Force for the work it accomplished over the past 30 months.

Respectfully submitted,

Francis J. Halpin
Bonneville Power Administration
Generation Scheduling
(503) 230-7545

From: Andrew C Dotterweich
Sent: Wednesday, October 26, 2005 9:25 AM
To: Veronica Thomason
Subject: Recommendation 2003 WEQ Annual Plan Item 6 - IIP (Inadvertent Interchange Payback)

Consumers Energy supports the October 10, 2005 Inadvertent Interchange Payback recommendation to not change any current standards or develop new standards.

_____

Andrew C. Dotterweich
Consumers Energy Company
Transmission and Regulatory Strategies
Room P13-106
1945 W. Parnall Road
Jackson, MI 49201

-----Original Message-----
From: Gregory Locke
Sent: Friday, October 28, 2005 8:57 AM
To: Veronica Thomason
Subject: Re: NAESB Wholesale Electric Quadrant Request for Comments - Comments Due November 14, 2005

Please accept the following comments regarding the Inadvertent Interchange Payback Task Force Final Report:

I believe that the "Recommendation to NAESB Executive Committee" (Recommendation) may mislead readers as to the findings of the IIPTF. The introduction to the IIPTF's report states "...the task force has determined the NAESB Version 0 Inadvertent Interchange Payback Standard is an appropriate (emphasis added) solution for the settlement of inadvertent interchange....". One must ask what "appropriate" means and the context in which the conclusion was reached.

Throughout the IIPTF's discussions, it was agreed that the payback-in-kind methodology is a flawed system at best. In fact, in the conclusion to its report, the IIPTF states that "...significant effort was expended...to develop a...settlement standard that would mitigate the potential financial gain that misuse of the payback-in-kind methodology does not prevent." (emphasis added).

Therefore, "appropriate" in this context means "The payback-in-kind methodology is subject to abuse, but we spent over 2 years arguing about it and couldn't come up with a better (i.e., from the balancing authorities' viewpoint) methodology so let's stick with the flawed system that we've already got."

The Recommendation states that "The task force determined that the standards included in Version 0 are sufficient and no changes are needed." This statement is very misleading because it mistakenly implies that the current unfair and flawed system is acceptable. It may be acceptable compared to the alternatives discussed by the task force, but it is definitely not acceptable in and of itself. The Recommendation therefore mischaracterizes the findings of the IIPTF.

What the Recommendation should say is: "The task force determined that the standards included in Version 0 are sufficient, given the lack of consensus regarding a better methodology."

I am in complete agreement with the comments made by Roy Thilly, Chairman of the Transmission Access Policy Study Group in his recent letters to Mr. Gent and the WEQ Executive Committee Members, i.e., the payback-in-kind methodology represented by Version 0 is discriminatory and should be replaced with a methodology that treats all stakeholders equally.

Member Name: Greg Locke
Member Company: ElectriCities of NC (North Carolina Eastern Municipal Power Agency)
Segment: Municipal

Gregory C. Locke
Manager, Strategic Analysis
ElectriCities of North Carolina
1427 Meadow Wood Blvd
Raleigh, NC 27604

Comments on NAESB IIPTF Recommendations

Howard F. Illian, President
Energy Mark, Inc.
Buffalo Grove, Illinois
November 14, 2005

Introduction:

I have participated in the processes for the development of the NERC Inadvertent Interchange Standards, FERC Energy Imbalance Tariffs, the NERC CACTF, the NERC JIITF, and the NAESB IIPTF over the last fifteen years as both a representative of a vertically integrated utility and as an independent party. As a participant in these forums, I have had the unique opportunity to observe the development of these standards, the recognition of their imperfections and the attempts to correct those imperfections. My comments include both observations on attempts to correct problems with inadvertent interchange / energy imbalance, and specific recommendations on the solutions that might lead to resolution of this problem.

History:

The concept of using payback-in-kind for inadvertent interchange is a carryover from an industry made up of vertically integrated utilities operating under cost-plus regulation. This concept was developed when there was little difference between marginal costs of energy among interconnected participants. The simple separation of energy between on-peak and off-peak periods was sufficient to represent differences in marginal cost variations over time. The small differences in cost recovery, resulting from inadvertent interchange payback-in-kind practice, was easily managed within the rate structure under cost-plus regulation.

In addition, most control areas that represented the vertically integrated utilities developed a climate of following good operating practice that continues today, maintaining reliability and good utility operating practices even under the pressures of the competitive markets. The habit of following good utility operating practice is a strong contributor to the maintenance of reliability today, but those habits are being eroded by market pressures.

As new generation technologies have been integrated into the interconnections and fuel supplies have diversified, this simple representation of price differences using only two pricing periods, is no longer adequate to represent the complexity of marginal prices today. As a consequence, the categorization of energy value into on-peak hours and off-peak hours is no longer capable of representing the value of energy adequately. Thus any method that continues to rely on this kind of price driven categorization will not resolve the problems resulting from marginal price variation on today's interconnections.

Energy Imbalance:

As a consequence of the issuance of FERC Orders 888 & 889, Energy Imbalance Tariffs were developed. At that time I was opposed to any imbalance tariff that would approximate the payback-in-kind methods used by control areas. The strong case was made that an Energy Imbalance Tariff that allowed energy to be repaid in kind without penalty would not maintain the necessary incentives to maintain reliability on the interconnections. As a consequence, Energy Imbalance Tariffs were developed around the, then current, model for emergency energy settlement. This resulted in Energy Imbalance Tariffs that are highly discriminatory in favor of the control area. This is preferable to implementing tariffs that could not support reliability.

The current imbalance tariffs are discriminatory because they have been written with the goal of forcing generators to conform to schedules through the use of penalties. The very use of the word "penalty" provides insight into the nature of the current tariffs. The word penalty fails to convey any need to understand the cost drivers associated with deviating from the schedules, the sole purpose is conformance. On the other hand, if the term "penalty" were to be replaced with the term "consequential incurred cost due to imbalance contribution," the discriminatory nature of the tariff would be removed. But, there would be little change in the outcome from both the incentive to follow schedules and the reliability of the interconnection. In addition, a change to the tariff of this nature would result in improved market efficiency because it would encourage all of the market participants to make economically efficient scheduling decisions.

The current imbalance tariffs contain both obvious and hidden discriminatory penalties in its six provisions.

- The minimum price when there is under-supply or over-demand of energy. This minimum price in many cases ($100 / MWh) is set well above expected market prices.
- The hourly dead-band percentages (+/- 1.5%) that segregates energy outside the dead-band.
- The percentage of cost penalty (+/- 10% of incremental or decremental cost) for energy outside the dead-band or energy not netted within a specific interval.
- The use of both incremental and decremental costs that may support different prices.
- The summing of all individual errors regardless of effect outside of the dead-band.
- Inflexibility that disallows schedule changes close to real time.[1]

Each of these provisions in the tariffs can result in discriminatory penalties that favor the control area.

A. Minimum Prices for Deviations are Discriminatory

If the minimum price is set well above the incremental price of energy at the time of the imbalance, settlement of that imbalance will result in a discriminatory penalty, whether the settlement is the result of exceeding the hourly deviation dead-band or the settlement is the result of not having offset errors within the allowed thirty day period. The industry has often used these kinds of minimum settlement prices between control areas to approximate the value of emergency energy, but they are misapplied when used for imbalance settlement. When used by control areas to settle deviations between control areas, the minimum applies to energy that flows in both directions, and therefore, the resulting revenue from this provision can flow in both directions. It is assumed that this bidirectional flow will tend to balance over the long term. When used for imbalance provisions, the minimum price only affects energy that flows to the transmission customer. There is no offsetting revenue flow in the opposite direction with imbalance as there is with bidirectional flows between control areas. Therefore, the minimum, when applied, always results in discrimination against the transmission customer without the opportunity for that discrimination to be offset by minimum charges in the reverse direction.

B. Hourly Dead-band Percentages are Discriminatory

Dead-bands by nature recognize that there are limits to how closely control action must be taken. They fail to recognize that there is no single fixed percentage that correctly provides for adequate error control. This is because there is diversity with respect to the way errors occur. If the total system can experience total error of 0.25 percent, it may be reasonable to

[1] This is not specifically included in the current tariff, but it is also not prohibited.

have a dead-band of 1.5 percent when the effects of average statistical error diversity are factored into the dead-band limit. Unfortunately, when the diversity of errors is significantly reduced, that reasonable dead-band can result in unreasonable total performance. Since diversity tends to vary on an electrical system from minute to minute and hour to hour, a fixed dead-band can only approximate an average limit, and is not capable of representing the best limit at any single time.

An example of this is easy to visualize. If one were to assume all the generators on the Eastern Interconnection were to operate within a limit of +/- 1.5%, the average frequency error would be well managed when those individual errors are independent from each other. The total frequency error for the interconnection would be quite small because many of the errors from under-generation would be offset by other concurrent errors from over-generation. This remains true as long as no outside influence causes all of these errors to be in the same direction. If all of the errors were to occur in the same direction, under-generation or over-generation, the resulting error approaching 1.5% would cause the interconnection to fail due to frequency operations outside of reliable limits. Factors that could influence this loss of diversity include weather that affects fuel supplies, extreme cold, extreme heat and unusual market prices. Under these conditions, the fixed dead-band will assign few penalties, while the interconnection experiences significant costs to maintain reliability of supply. The dead-band structure requires that these costs be recovered through the penalties that are assessed at other times when the reliability problems and costs are less serious because they naturally offset each other. It is this inability to assign cost responsibility at the time of occurrence that causes fixed percentage dead-bands to be discriminatory.

C. Penalties Based on Percentage of Cost are Discriminatory

The penalties are based on the assumption that costs associated with managing imbalances are proportional to costs of energy. This is not true. The reasons for this can be discovered by looking at cost drivers associated with energy, capacity supply and pricing. Electric energy cannot be economically stored. As a consequence, the prices in one hour may not be closely related to the prices in the next hour. This is confirmed by the price volatility that the electric markets experience. When the prices are compared from week to week, they become even less dependent on previous interval prices. In addition, generation margin must be held ready to manage errors in both supply and demand. Not only are reserves required to manage intervals of under-supply and over-use, but back-down margin is required to manage interval of over-supply and under-use. Although the value of energy from these resources may have a weak relationship to energy prices, the value of the capacity and response costs associated with standing-ready-to-supply from these resources are not strongly related to the energy price but are instead related to capacity value. This cost is represented best by the prices in the ancillary service markets. In addition, the management of reserves and operating margins should be done with the goal of managing the cost of reliability risk. Therefore, the best solution to the imbalance problem is to trade reliability risk from one hour to the next to minimize the total cost of the total risk. Since energy cannot be stored, this interval to interval trading of energy is not available for energy. Therefore, the prices of energy and the prices of imbalance management are driven by different market characteristics and their pricing is not strongly related. If the prices of energy and imbalance reliability risk are not strongly related, the setting of prices for imbalance reliability risk based on energy price will be discriminatory.

D. Use of Different Incremental and Decremental Prices can be Discriminatory

The net error on an interconnection can only be one direction at a single point in time. The interconnection will either be over-generating or under-generating. If both incremental and decremental prices are use for the same interval, then the price difference between the incremental price and the decremental price will result in discriminatory pricing for some customers. In many markets, the pricing interval for the forward market is one hour, and therefore, the netting interval should also be one hour. Correct procedure should use incremental prices when the interconnection is under-generating and additional incremental energy must be supplied, and decremental prices when the interconnection is over-generating and energy must absorbed. Only one of these two conditions can exist for any pricing interval on the interconnection. If the tariff is written to allow the concurrent use of both incremental and decremental pricing and those prices are different, the resulting pricing will be discriminatory.

E. The Summing of Errors Outside the Dead-band is Discriminatory

The effect of errors on imbalance reliability is not the result of individual errors but the result of net errors at any point in time. This means that if there are two generators and one has an over-generation error of 100 MW and the other has an under-generation error of 100 MW, the effect on imbalance reliability is proportional to the net sum of the errors. In this case, there would be no reliability effect because the sum of the errors is zero. When errors outside of the dead-band are summed without first netting those errors, the revenue resulting from summing those individual errors is much greater than the revenue that would be derived from the net error. It is the difference between the sum of the individual errors and net error that is discriminatory. Although it is not appropriate to sum absolute errors within a single interval it is appropriate to sum net errors across intervals. This appropriateness of summing errors across intervals is a consequence of the inability to store electric energy. This is also supported by the changes in price between intervals that would be arbitraged by the market if energy could be economically stored.

F. Not Allowing Schedule Changes Close to the Real-time is Discriminatory

Current tariffs that have been implemented without provisions that enable resources to change their schedules close to real-time are discriminatory because they result in larger penalties being assessed against resources that have large uncertainties associated with the differences between their day-ahead forecast and their hour-ahead (close to real-time) forecast. Day-ahead forecasting has been acceptable practice in the industry because installed technologies have minimal uncertainty associated with the difference between day-ahead and hour-ahead forecasts. When changes in forecasts are prohibited close to real-time, this discriminates against the intermittent resource because they are prohibited from changing their forecast despite available measures to mitigate much of the resulting detrimental effects.

There is a principle in tort law that states that a party that has suffered a loss is not entitled to recover avoidable costs of that loss if there were actions that could have been taken to mitigate the size of the loss incurred. By prohibiting changes in schedule close to real-time the tariff would bypass any opportunity that changes in schedule would make available for the total or partial mitigation of the costs associated with that schedule change. The objective of the tariff should be to encourage good operations and penalize bad operations, not insure that those unable to make good forecasts are punished by imbalance penalties.

G. The Summing of Errors Outside the Dead-band Discourages "Good Operating Practice" and is Detrimental to Reliability

The above characteristic of summing of errors outside of the dead-band that exists in both the current and proposed tariffs is the most damaging characteristic because not only is it discriminatory but it also encourages deviation from "good operating practice" to the detriment of interconnection reliability. The following example demonstrates this problem.

Example of Incentive to Deviate from "Good Operating Practice"

One of the most important aspects of "good operating practice" for electric generators is the requirement that generators have a governor and operate the generator in a manner that allows that governor to provide a 5% Droop Characteristic. This requirement has been included in both NERC Planning and Operating Standards. A generator following "good operating practice" will automatically provide an increase or decrease from their scheduled output that includes this governor response.[2] An interesting observation is that a generator operating in this manner, following "good operating practice" will exceed the 1.5% dead-band when ever the interconnection frequency deviates more than 45 mHz from schedule. In addition, if the schedule is only part of the generator capability, a 500 MW generator serving a 250 MW schedule, the response is based on the capacity of the generator, not on the size of the schedule. In this case of a partially loaded generator, it would only require a 22.5 mHz frequency deviation to trigger the 1.5% dead-band on the 250 MW schedule. It should be unacceptable for any market based rule to penalize a generator for following "good operating practice." This incentive to deviate from "good operating practice" is more detrimental than any discriminatory pricing aspect of the tariff, because it is detrimental to interconnection reliability.

Energy Imbalance Summary:

All of the above discriminatory characteristics of the Energy Imbalance Tariffs discriminate in favor of the Control Area. The net effect of these is to generate significant excess revenue beyond the real costs of providing the balancing function. This excess revenue is a powerful incentive for the control areas to oppose any change in the Energy Imbalance Tariffs.

Inadvertent Interchange:

The current Inadvertent Interchange settlement practice using payback-in-kind of energy without penalty also works in favor of the control area in that any energy imbalance that the control area fails to offset is simply transferred to the interconnection without penalty as long as the control area is meeting its CPS1 criteria. The marginal cost of that energy is not charged to the control area and the control area is allowed to return the unmanaged error later with energy payback-in-kind. It is this difference that creates the problem we are attempting to address. The difference between the cost of operating under the Energy Imbalance Tariff and the Inadvertent Interchange payback-in-kind methodology provides a large discriminatory advantage to the control area when competing against the non-control area as an energy supplier.

When the current handling of Inadvertent Interchange with payback-in-kind without penalty is coupled with the current Energy Imbalance Tariffs that penalize even offsetting errors at above

[2] A 5% Droop indicates that a 5% change in interconnection frequency will cause the governor of the generating unit to adjust output by 100% of the capacity of the generator in a direction to oppose the change in frequency. This translates into a 20% change in generator output for each 1% change in interconnection frequency.

market prices, the coupling of the two methods together creates a significant revenue advantage for the control area and its affiliated generation that strongly discriminates against those market participants that are not control areas.

NERC Joint Inadvertent Interchange Task Force:

The charge of the NERC Joint Inadvertent Interchange Task Force was to develop a solution to the problems associated with using payback-in-kind for Inadvertent Interchange by recommending changes to the handling of Inadvertent Interchange that would remove the discriminatory consequences of using current Inadvertent Interchange practice. The initial suggestion that the JIITF considered was simply to replace the payback-in-kind method with financial settlement of the energy at market prices. Discussion within the JIITF soon revealed that there were reliability considerations that are not universally included in the current market prices of energy. The JIITF also concluded that in addition to a price to represent the Energy Component of Inadvertent Interchange there must also be two reliability components included in the price also. One of those reliability components would represent the incremental or marginal value of Transmission Congestion Component and the other reliability component would represent the incremental of marginal value of the Frequency Control Component. This Frequency Control Component would include the costs associated with maintaining and supplying capacity margin and reserves necessary to control frequency.

The JIITF also decided two other issues at the insistence of some of the participants. The first was that the JIITF should not address the Energy Imbalance Tariffs because they are under FERC jurisdiction. This decision was made even though the theory upon which the JIITF Recommendation is based could also be applied effectively to Energy Imbalance. The second was that determination of the Energy Component of Inadvertent Interchange was not a reliability issue but a commercial issue, and therefore, the problem of pricing the energy should be passed on to NAESB. These decisions would insure that any implementation of the JIITF Recommendations would be delayed at a minimum until NAESB would be able to address the issue. Approximately six months later (January 2003), NAESB began its work on Inadvertent Interchange.

NAESB Inadvertent Interchange Payback Task Force:

The NAESB IIPTF began with an honest effort to find solutions to the problems associated with use of the Inadvertent Interchange Payback-In-Kind methods. These discussions and investigations went reasonably well for the first year of this process. However, near the end of the first year(2003), there was a sudden change in the direction of these proceedings. The task force voted to exclude consideration or discussion of any issues internal to Control Areas, ISOs or RTOs. Shortly thereafter, they voted to eliminate any consideration or discussion of the inclusion of a Frequency Control Component even though they did not have any viable alternatives developed to replace the payback-in kind method. Some of those voting indicated that they thought that the multi-part pricing required by a Frequency Control Component was too complex for the industry. This statement was made even though this industry has used multi-part pricing since early in the 20th century shortly after its birth.

These votes were by no means unanimous. They tended to split between those parties representing incumbent control areas and those parties that did not represent incumbent control areas. Later the task force voted to send some of the issues back to NERC because they included issues that involved reliability. This split continued though the completion of the final report and recommendation. The only consensus that was achieved was that there would be no consensus on a methodology that could replace the current payback-in-kind methodology. It

appeared to me that the incumbent control area representatives realized that with their majority position, they had no incentive to resolve this problem.

Even though there was no consensus for a replacement method to manage Inadvertent Interchange, the task force was able to produce a body of work that I believe could provide the basis for eventually resolving this problem using the template provided by the NERC JIITF. Work papers produced by this task force contain significant useful information and recommendations that will eventually help with resolution of the problem.

The NAESB IIPTF decided that it was incapable of arriving at a consensus and resolving issues that involved reliability. It included in its recommendations, work that should be passed back to NERC for resolution. It also demonstrated that as long as the organization attempting to resolve this issue is made up of a majority of participants representing incumbent control areas, there is little hope that any organization so comprised will choose to eliminate the revenue source generated by the unequal handling of Energy Imbalance as compared to Inadvertent Interchange.

Lessons Learned:

I believe that the following lessons can be learned from observing this process over the last few years.

1. This issue will not be resolve on a piecemeal basis. If commercial considerations are separated from reliability considerations, those opposing change will continue to divide the recommended solutions and defeat them piecemeal. Only a task force that can consider both commercial and reliability issues together will have any hope of arriving at a consensus to resolve this problem.
2. Since significant portions of the discriminatory nature of the difference between the handling of Inadvertent Interchange and Energy Imbalance are contained both in the NERC Inadvertent Interchange Standard and the Energy Imbalance Tariff, the discrimination cannot be eliminated through the modification of either alone. Full equity can only be achieved through the modification of both to be consistent with each other. This may require the development of a common methodology first and then two implementation processes, one each for Inadvertent Interchange and Energy Imbalance.
3. It will be easy for those opposed to modification of the current methods to continue to use the divide and conquer strategy to delay implementation of those actions necessary to eliminate the discrimination resulting from the differences between these two settlement methods.
4. As long as the industry fails to recognize that imbalances between load and generation have the same reliability effect on the interconnection regardless of whether we name these imbalances Inadvertent Interchange or Energy Imbalance, we will be unable to arrive at a consensus on this issue. The difference lies not with the imbalance but with how the responsibility for managing it is assigned.

Recommendation:

NAESB and NERC should immediately create a joint body that includes both commercial and reliability experts from all segments of the industry to make another attempt to develop a solution to this problem. That body should be instructed to investigate both the handling of Inadvertent Interchange Settlement and Energy Imbalance Tariffs with the sole goal of developing a method or alternative methods that eliminate the discrimination resulting from the differences between settlement methods for these two kinds of load-generation imbalance. The first responsibility of this body should not be to judge whether the non-discriminatory method is worth implementing. Only after non-discriminatory method(s) have been developed should evaluation of the cost-benefit of implementation be considered. It is my judgment that any body that considers cost-benefit as part of the development of a non-discriminatory process will be unable to develop a method that is really non-discriminatory. Once a non-discriminatory method is developed, it should then be much easier to simplify that non-discriminatory method to make it feasible for implementation while maintaining its non-discriminatory nature, than to create a simplified non-discriminatory method directly. This path is recommended because the understanding acquired while developing the non-discriminatory process will guide the simplification process. Only a joint NERC-NAESB body will be in a position to make a recommendation to FERC once that body has completed its work.

REJECT THE IIPTF RECOMMENDATION. As a member of the IIPTF, I recommend (a) rejecting the IIPTF's recommendation to continue use of the NAESB Version-0 Inadvertent Interchange Payback Standard, and (b) remanding the IIPTF, a new taskforce, or NERC to the IIPTF's original charge[1] of (i)"mitigating the potential financial gain that misuse of the current payback-in-kind methodology fails to prevent" and (ii) doing this by using "the work of the NERC Joint Inadvertent Interchange Task Force … as the initial model for development and enhancement of the required standard or standards" and departing from it only by specifically demonstrating how that model would not work. This needs to be done for the following reasons.

UNFAIRNESS ACKNOWLEDGED. The NAESB IIPTF originally acknowledged[1] the unfairness and financial abuse inherent in the current Inadvertent Interchange Payback practice.that has since been translated into the NERC and NAESB Version-0 standards that, following the August 14th, 2003, Blackout, codified current NERC policy.

RECENT COMPLAINT FILED WITH FERC. Wisconsin Public Power's Roy Thilly, Chairman of the independent 33-state Transmission Access Policy Study (TAPS) Group (of mostly municipal utilities), has just reacknowledged the same unfairness and financial abuse in his July 22, 2005, letter to NERC's then-President and to the NAESB Wholesale Electric Quadrant (WEQ) and in his August 29th reply to NERC's then-President (appendixed to TAPS's ERO filing to FERC http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/051007commentsrm05-30.pdf , with NERC's then-President's August 9th reply posted by the IIPTF as http://www.naesb.org/pdf2/weq_iiptf081905w2.pdf), by complaining about discrimination due to non"comparability" between inadvertent interchange payback and energy imbalance. Mr. Thilly concluded his correspondence by recommending (a) rejection by NAESB's WEQ of the IIPTF's recommendation, and (b) remanding the noncomparability issue back to a NAESB taskforce or to NERC for resolution and, if they fail, to FERC.

NERC'S EARLY RECOGNITION. NERC long ago recognized[2] this incomparability as unacceptable and as a result formed the Control Area Criteria Taskforce (CACTF) on which I served and that resulted (after a year or two) in the NERC Functional Model that defined the specific NERC function of "balancing" to which the incomparability applied.

NERC'S EARLY SOLUTION. NERC subsequently formed the Joint Inadvertent Interchange Taskforce (JIITF) on which I also served and whose Whitepaper (developed in 9 months) solved the incomparability by identifying three "components" of Inadvertent Interchange, including an "energy" component (and sometimes a separate "transmission" congestion component) easily made comparable to energy imbalance[3], and a separate "frequency contribution" reliability component (FCC) ignored in energy imbalance. FCC was needed to eliminate existing financial incentives to using energy imbalances to raise the cost of (instantaneous balancing) reliability, and to remove financial disincentives to using energy imbalances to reduce the cost of (instantaneous balancing) reliability, incentives and disincentives that are independent of the cost of the energy itself. Ultimately, the energy imbalance tariff itself would need replacing by a compatible 2-part or 3-part tariff that passes the NERC JIITF Inadvertent Interchange settlement through to the end users responsible.

IIPTF SHORT-CIRCUITED. The NAESB IIPTF acknowledged[1] the NERC JIITF Whitepaper as the "initial model" for the NAESB IIPTF's subsequent work. After 2 1/2 years the NAESB IIPTF has

COMMENTS ON THE RECOMMENDATION RE
2003 WEQ ANNUAL PLAN ITEM 6 - IIP (INADVERTENT INTERCHANGE PAYBACK) MADE BY THE
INADVERTENT INTERCHANGE PAYBACK TASKFORCE TO THE
WHOLESALE ELECTRIC QUADRANT EXECUTIVE COMMITTEE OF THE
NORTH AMERICAN ENERGY STANDARDS BOARD

decided instead to endorse the current Inadvertent Interchange Payback practice, which includes the unfairness and financial abuse the IIPTF[1] and NERC[2,3] originally acknowledged is inherent in it, while making no attempt to deny the seriousness of the unfairness or financial abuse that independent TAPS Chairman Thilly considers persists unabated (http://www.naesb.org/pdf2/weq_iiptf081905w2.pdf).

NERC JIITF WHITEPAPER UNREFUTED. Meanwhile, throughout the NAESB IIPTF's proceedings no document or argument was ever posted or offered to disprove any finding of the NERC JIITF "initial model" but, midway through its proceedings, the NAESB IIPTF voted to reject outright the NERC JIITF "initial model" and never even submit it for industry comment.

INDUSTRY DID NOT SUPPORT LACK OF SOLUTIONS. The NAESB IIPTF presented for industry comment little choice of alternative to the current NAESB and NERC Inadvertent Payback Version-0 Standard. Of the two trivial "alternatives" offered for comment, one left virtually all of Inadvertent Interchange in a "deadband" where it would be governed by the same policy as the current NERC and NAESB Version-0 Standards, and the other proposed a payback-in-kind mechanism that is already in use in the Western Electricity Coordinating Council (WECC) interconnection and is therefore included in the current NERC and NAESB Version-0 Standards for Inadvertent Interchange Payback. The few industry comments received did not support either of these non-alternatives to current practice.

PRESENT OPPORTUNITY TO COMMENT ON NERC JIITF. The current comment period on the NAESB IIPTF's recommendation to the WEQ now enables the industry finally to comment on the NERC JIITF "initial model" against the posted technical record[4] that supports it, albeit with no endorsement by the NAESB IIPTF of it or of any other solution to the current Version-0 Inadvertent Interchange Payback Standards' unfairness and financial abuse problems that the IIPTF[1] and NERC[2,3] have acknowledged and never subsequently denied.

UNFAIRNESS AND FINANCIAL ABUSE. NERC originally[2] identified a two-fold unfairness rooted in the disparity between inadvertent interchange payback from control areas to their Interconnection, and energy imbalance penalties assessed generators. NERC identified that unfairness as prompting generators to become control areas to equalize the disparity but not necessarily to reduce the financial abuse.

1. DISPARITY[2,3]. As control areas, large transmission owners or operators have been able to benefit from charging transmission customers (including independent generators) the energy imbalance tariff on all deviations that is punitive whether or not the deviations contribute to or alleviate frequency deviation (unreliability), while those large transmission owners or operators are not in turn assessed for such imbalances, but are subject monthly only to a rolling annual performance limit that recognizes an imbalance as helping or hurting frequency, and they can pass their additional cost of control through to their transmission customers or end-users.

2. PARKING OR BANKING[2,3]. Furthermore, control areas are not assessed the energy cost of imbalances, but can "park" those imbalances over (often indefinite) time and pay back the energy in kind when the price is much cheaper than when the imbalance occurred, or can use imbalance energy to circumvent congestion charges.

NERC NOW PROPOSING ATEC THAT WAS UNSUPPORTED BY NAESB INDUSTRY POLL. During the present NAESB comment period, NERC's Resources Subcommittee is preparing an omnibus Standards

SUBMITTED BY ROBERT BLOHM
OCTOBER 20, 2005

Authorization Request for a raft of six operating standards that include an inadvertent interchange payback standard called BAL-004-1 "Time Error Correction" that would extend the WECC interconnection's Automatic Time-Error Correction (ATEC) to the Eastern Interconnection and to ERCOT. But the NAESB IIPTF final report (http://www.naesb.org/pdf2/2003ap6_iip_rec_attachment.doc, page 5) states that ATEC was not supported by industry comments when proposed by the NAESB IIPTF as a standard for inadvertent interchange payback, and the report leaves to NERC any further promotion of it.

ATEC NOT AN ALTERNATIVE. ATEC does reduce the parking or banking period but does not eliminate this aspect #2 of the inadvertent interchange payback/settlement problem (see "WATEC Gaming Example" http://www.naesb.org/pdf2/weq_iiptf041205w3.xls posted by Tony A. Reed of Southern Company Generation and Energy Marketing to the IIPTF webpage on April 12, 2005, and acknowledged http://www.naesb.org/pdf2/weq_iiptf041205w1.doc by Nick Henery of SMUD). This is true especially as there is much more congestion in the Eastern Interconnection than in WECC where ATEC is currently in use and included in the current NERC and NAESB Version-0 Standards for Inadvertent Interchange Payback and where the need to cap the payback amount to avert creating congestion forces the parking or banking period to be extended. The gaming can consist of taking inadvertent when prices are highest and paying back when the average price over the extended payback period is lower. Nor does ATEC solve the penalty disparity aspect #1 of the inadvertent interchange payback/settlement problem. Properly solving problems 1 & 2 would reduce sustained time error and the need for ATEC itself which addresses a mere symptom (time error) whose correction can be irrelevant to electric reliability and an anachronism in an age of digital timekeeping.

Footnotes

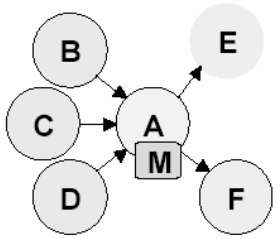
[1] Question 4 of March 6, 2003, *Request to NAESB for Initiation of an Interchange Payback Standard*:
"Use of Proposed Standard or Enhancement (include how the standard will be used, documentation on the description of the proposed standard, any existing documentation of the proposed standard, and required communication protocols):
The standard or standards will define the alternatives that may be used to settle Inadvertent Interchange while mitigating the potential financial gain that misuse of the current payback-in-kind methodology fails to prevent. The work of the NERC Joint Inadvertent Interchange Task Force will be used as the initial model for development and enhancement of the required standard or standards that may include energy, transmission and frequency components of Inadvertent Interchange."

[2] Pp 51-53 of NERC's *1999 Reliability Assessment*:
"***New Role for Control Areas***
For literally decades, NERC Operating Policies have centered on the control area as the basic entity for providing the services that ensure the operating security of the Interconnections. These services include generation-demand balancing, interchange scheduling and accounting, and transmission security. The typical NERC Operating Policy begins with "the control area shall…." Fundamental changes in our industry have resulted in a new way to view the control area concept, and an unexpected interest by generator owners to form new control areas. These changes include:
1. the separation of the transmission and generation sectors,
2. the apparent disparity between inadvertent interchange payback from control areas to their Interconnection and energy imbalance penalties assessed generators, and
3. merchants seeking the greater scheduling flexibility afforded to control areas.

COMMENTS ON THE RECOMMENDATION RE
2003 WEQ ANNUAL PLAN ITEM 6 - IIP (INADVERTENT INTERCHANGE PAYBACK) MADE BY THE
INADVERTENT INTERCHANGE PAYBACK TASKFORCE TO THE
WHOLESALE ELECTRIC QUADRANT EXECUTIVE COMMITTEE OF THE
NORTH AMERICAN ENERGY STANDARDS BOARD

Inadvertent Interchange Versus Energy Imbalance
Mismatches between a control area's actual and scheduled interchange may be due to the control area's inaccurate generation control, or to its response to Interconnection frequency errors (when the Interconnection's frequency is above or below 60 Hz). In essence, the first (control problems) creates the second (frequency errors).
Poor control creates an inadvertent interchange between the control area and its Interconnection, and equates to energy either owed to or from the Interconnection. This energy difference is inadvertent interchange. At present, NERC does not specify how much inadvertent a control area may accrue before it must repay. And repayment is with "in-kind" (on- or off-peak) energy, not dollars.
Merchant power producers, however, are generally held to a stricter standard and must pay energy imbalance penalties (dollars) if their generation does not match the schedule they have committed to with their host control area. This different approach may be leading some generators to become control areas, where generation mismatch can be repaid through NERC's inadvertent interchange policies rather than energy imbalance penalties.

Scheduling Flexibility
Control areas also provide the ability to "bank" Interchange Schedules and to provide a "hub" service between a collection of generation sources and customers. In fact, a control area is the only mechanism provided in the Operating Policies that allows Interchange Scheduling.



Consider the diagram on the left. Control area A's affiliate merchant M can schedule interchange from generation in control areas B, C, and D, and sell to customers in control areas E and F. The merchant's control area allows him the flexibility to set up separate purchases and sales by providing a means to bank future interchange transactions and providing a hub to "mix and match" products and customers. In other words, these do not have to be bilateral transactions between the ultimate sources and customers.
The control area's ability to mix and match generation products and customers has not gone unnoticed. The merchant generator in SERC has established itself as three separate generation-only control areas, which gives its marketer the ability to hub generation purchases for a variety of its customers. Other merchant producers have expressed a similar interest in becoming control areas.
To address the rapidly changing role of the control area, the Security Committee established a control area Criteria Task Force. Its charge is to look at all the reliability functions necessary for operational security, and recommend which entities — control areas, transmission operators and providers, generation operators, and so on — provide these functions. This task force is also charged with investigating the needs of the marketplace and recommending new functions and entities to provide these needs. One possibility would be to devise a way to provide the banking and hubbing services to the marketplace without requiring merchant generators to be control areas."

[3] Pp. 3,4, *Recommendations for the Wholesale Electric Industry of North America: Inadvertent Interchange*, Draft 5d, May 10, 2002. A White Paper Prepared by the NERC Joint Inadvertent Interchange Task Force
"**Commercial Advantages**
The emergence of regional power markets in recent years has created new challenges for the operation of the interconnected power system not anticipated in current NERC Policies and

SUBMITTED BY ROBERT BLOHM
OCTOBER 20, 2005

Standards. The CACTF identified a practice in the NERC Operating Policies that appears to afford a Balancing Authority's affiliated generators and marketers a commercial advantage over their independent counterparts. This practice is the use of Inadvertent Interchange by Balancing Authorities vs. Energy Imbalance compensation by non-control areas.

Inadvertent Interchange versus Energy Imbalance

The commercial advantage a "traditional" Balancing Authority with affiliated generation has over an independent generator is the method for settling energy imbalances. Specifically, the Balancing Authority satisfies NERC inadvertent rules by repaying with in-kind energy (On- or Off-Peak) at its discretion, while an independent generator (non-Control Area) repays imbalance in accordance with the host Balancing Authority's contract; possibly at market prices.

Before market-based energy rates were allowed, reconciliation of Inadvertent Interchange with energy only was considered to be an equitable one-for-one settlement methodology. Cost-based energy prices, allowed at the time, were not volatile. Ten years ago the marketplace did not see energy prices in the $100+ range. Also, there was a general understanding that Balancing Authorities were on both sides of the inadvertent balance, sometimes long, sometimes short. Today, when energy prices become very high, a Balancing Authority can "lean" on the Interconnection and accrue an inadvertent balance. The respective Balancing Authority can then repay that balance with energy days, months, or years later when energy prices are lower.

Comparison Arguments. By definition, Balancing Authorities' Inadvertent Interchange cannot be equally compared to Independent Generators' Energy Imbalance. However, the settlement of the Inadvertent energy component and the Energy Imbalance could be made to be comparable. Creating 3 Inadvertent Interchange Standards, one addressing the transmission component, one addressing the frequency component and one addressing the energy component, will allow the Inadvertent energy to be settled in a manner comparable to settlement of Energy Imbalance."

[4] Including 43 comment postings by R. Blohm to the IIP Taskforce (in chronological order):

http://www.naesb.org/pdf/weq_iiptf021903w4.pdf
http://www.naesb.org/pdf/weq_iiptf033103w1.pdf
http://www.naesb.org/pdf/weq_iiptf040903w1.pdf
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SUBMITTED BY ROBERT BLOHM
OCTOBER 20, 2005

From: Butts, Marc M.
Sent: Monday, November 14, 2005 1:46 PM
To: naesbmail@naesb.org
Subject: Inadvertent Interchange Payback Task Force (IIPTF) Final Report

Dear sirs,

On behalf of Southern Company - Transmission, we have no comments on the "Inadvertent Interchange Payback Task Force (IIPTF) Final Report". We commend the hard work of the task force and appreciate their efforts.

Thanks,
Marc

Marc M. Butts
Southern Company Services
Bulk Power Operations
205-257-4839
mmbutts@southernco.com

TAPS

Web Site ◆
www.tapsgroup.org

July 22, 2005

CONTACTS ◆
Roy Thilly, Chairman
Wisconsin Public Power Inc.
1425 Corporate Center Drive
Sun Prairie, WI 53590
608.834.4500
Fax 608.837.0274
rthilly@wppisys.org

◆
Robert McDiarmid
Cindy Bogorad
Spiegel & McDiarmid
1333 New Hampshire Avenue, NW
Washington, DC 20036
202.879.4000
Fax 202.393.2866
robert.mcdiarmid@spiegelmcd.com
cynthia.bogorad@spiegelmcd.com

◆
Deborah Sliz
Morgan Meguire LLC
1225 I Street, NW
Suite 300
Washington, DC 20005
202.661.6192
Fax 202.661.6182
dsliz@morganmeguire.com

◆
Robert Talley
Talley & Associates
2121 K Street, NW
Suite 650
Washington, DC 20037
202.296.4114
Fax 202.296.2409
Tmg1@erols.com

WEQ Executive Committee
North American Energy
Standards Board
1301 Fannin, Suite 2350
Houston, TX 77002

Michehl R. Gent
President & CEO
North American Electric Reliability Council
116-390 Village Boulevard
Princeton, NJ 08540

Re: Inadvertent Interchange Payback

Dear Mr. Gent and WEQ Executive Committee Members:

I am writing to NERC and NAESB on behalf of the Transmission Access Policy Study Group (TAPS) to request that in future consideration of the treatment of inadvertent energy, an important comparability issue does not get overlooked —*i.e.*, allowing return-in-kind treatment of inadvertent energy among control areas, while non-control area utilities are burdened with punitive imbalance charges.

The TAPS group is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access. TAPS members have been following the progress of NAESB's Inadvertent Interchange Payback Task Force (IIPTF). We were pleased to see the establishment of the IIPTF in March of 2003 with the goal of developing standards to define the alternatives that may be used to settle inadvertent interchange, particularly the mitigation of the potential financial gain that misuse of the payback-in-kind methodology does not prevent. However, we are disappointed that, after 27 months and the consideration of numerous proposals to replace the current payment-in-kind methodology of settling inadvertent energy accounts between control areas/balancing authorities, the IIPTF was unable to reach agreement on an improved system and so concluded in its June 1 memo discussing Task Force results, that "…none of the proposed solutions… better than the payback-in-kind methodology (as embodied in the NAESB Version 0 Inadvertent Interchange Payback Standard)." The result would leave a clearly discriminatory practice in place. We understand that the final IIPTF report will be considered by WEQ at its November meeting.

We also understand that NERC has asked that NAESB's Inadvertent Interchange Payback standard (WEQBPS) be transferred to NERC's and included as a reliability standard, and is drafting a Standards Authorization Requests (SAR) for this standard. (For that reason, NERC on June 24 asked FERC to defer action on NAESB's proposed Version 0 standard in FERC Docket No. RM05-5-000.) This proposed transfer will also bring aspects of this issue shortly before both WEQ (for action on the SAR) and NERC.

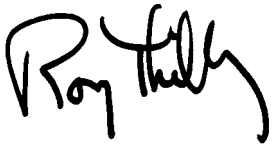
Thus, the inadvertent energy payback issue may soon be before NERC and/or WEQ. We ask that such consideration resolve, and not avoid, the fundamental comparability issue, rather than simply perpetuate a flawed and discriminatory system. Specifically, the payback-in-kind methodology for inadvertent energy between control areas is clearly not comparable to the treatment of imbalances experienced by non-control area utilities under FERC's open access tariffs. For non-control area utilities, return-in-kind provisions are typically limited to imbalances within a narrow 1.5% deadband, with under-deliveries beyond the deadband charged $100/MWh or 110% of incremental cost for under-deliveries (whichever is higher), with payments of 90% of decremental cost for over-deliveries. Payback in kind of inadvertent energy avoids these penalty aspects of the tariff completely. Neither the NERC nor NAESB standard should be designed to create or perpetuate competitive advantages for control area operators. This is important not only to achieve fundamental fairness, but also to avoid creating an obvious additional impediment to reasonable control area consolidation.

Whether through NAESB or NERC, the current discriminatory system of payback-in-kind should be replaced with a methodology that treats all utilities equally. As FERC, in Order 2000, concluded:[1]

> In the NOPR, we noted that unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. We conclude that control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory.

Because much of the nation will not have RTO balancing markets any time soon, it is critical that any policies promote a non-discriminatory system to manage inadvertent energy flows. Therefore, we ask the WEQ Executive Committee to reject the recommendation of the IIPTF and direct the IIPTF to develop a methodology that does not perpetuate what FERC has recognized to be a discriminatory treatment of imbalances. To the extent the issue is transferred to NERC, NERC should do the same. If NERC and/or NAESB cannot deal with this fundamental comparability issue (*e.g.*, because sufficient consensus is not possible), they should clearly inform FERC of this problem, identifying the comparability concern as a tariff issue that should be addressed by FERC.

Very truly yours,



Roy Thilly

cc: TAPS Members
Allen Mosher, APPA

[1] *Regional Transmission Organizations*, Order 2000, FERC Stat. & Regs. ¶ 31,089, at 31,142 (1999).

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

TO: NAESB WEQ Files

FROM: Rae McQuade

RE: NAESB Response to TAPs Communication on IIP, received July 28, 2005

DATE: July 28, 2005

From: Rae Mcquade

Sent: Thursday, July 28, 2005 4:24 PM

To: Cynthia S. Bogorad; Allen Mosher; Roy Thilly

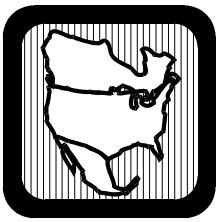
Cc: Michehl R. Gent; Don Benjamin; David N. Cook; Barry R. Lawson Michael Desselle; Louis Oberski; Phil Cox; Kathy York; Tony A Reed; Mark Fidrych; Veronica Thomason

Subject: TAPs comments to NAESB on inadvertent interchange

Dear Mr. Thilly,

We have received your comments on our efforts in regard to inadvertent interchange, and have posted those comments on our web site at the following address: http://www.naesb.org/pdf2/weq_ec082305w1.zip. We placed the discussion of those comments on the agenda for the upcoming NAESB Executive Committee meeting on August 23, in Colorado Springs, as part of the "Subcommittee Updates" agenda item no. 3. Please feel free to join in those discussions, or have other TAPs members join the meeting. The meeting is accessible via conference call if travel to Colorado Springs is not feasible. Thank you for sending the comments and making our committee aware of TAPs concerns. We look forward to hearing from you and other TAPs members -- Best Regards, Rae

Rae McQuade, President, NAESB
1301 Fannin, Suite 2350, Houston, Texas 77002
713-356-0060 (phone), 713-356-0067 (fax),
281-830-7406 (cell), www.naesb.org (web)



MICHEHL R. GENT
President and CEO

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

August 9, 2005

Mr. Roy Thilly
Chairman
Transmission Access Policy Study Group
Wisconsin Public Power Inc.
1425 Corporate Center Drive
Sun Prairie, Wisconsin 53590

Dear Roy:

Inadvertent Interchange Payback

This is in response to your July 22, 2005 letter to me and the NAESB Wholesale Electric Quadrant regarding the comparability between inadvertent interchange payback and energy imbalance. I understand that you and Don Benjamin talked about this in San Diego last week.

The inadvertent-energy imbalance comparability issue arose frequently within NERC committees soon after the Commission promulgated its *pro forma* tariff. In fact, this is one of the issues that resulted in NERC developing our reliability functional model.

We have debated the characteristics of inadvertent interchange over many years. Specifically:

1. Inadvertent interchange is between a balancing authority and the Interconnection, not between two individual balancing authorities. In other words, inadvertent interchange is not a bilateral arrangement.

2. Inadvertent interchange has two forms: 1.) Inadvertent caused by imperfect generation control that we call “primary inadvertent,” and 2.) Inadvertent caused by Interconnection frequency error that we call “secondary inadvertent” (the result of other balancing authorities’ primary inadvertent). How should the values of these different forms of inadvertent interchange be determined?

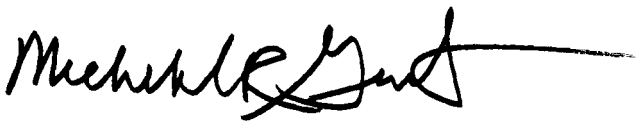
Therefore, while inadvertent interchange appears to have many of the attributes of energy imbalance, they are not the same, and I question whether they can be dealt with on the comparable basis that you are suggesting.

It appears to me that NERC and NAESB have both worked hard on inadvertent settlement methods, with NAESB's Inadvertent Interchange Payback Task Force delving into these concepts further than any group we're aware of. Despite the considerable discussions by industry experts, including economists, the IIPTF realized the practical hurdles of calculating Interconnection market prices and values for frequency response couldn't be crossed. Don explained this at the Stakeholders Committee meeting.

NERC is committed to ensure that our standards do not unduly discriminate among the responsible entities to which those standards apply. Standards that apply to balancing authorities must apply comparably to all balancing authorities. However, NERC cannot ensure that standards that apply to balancing authorities will be economically comparable to tariff rules or other protocols that apply to other transmission customers such as generators or load-serving entities, and that NERC has no influence over.

Roy, I believe NERC and NAESB have thoroughly debated inadvertent payback possibilities over many years. We believe NAESB should continue to set the on- and off-peak periods and develop whatever financial payback provisions that industry may agree upon in the future. Both NERC and NAESB have very open standards development processes that will welcome your thoughtful insight.

Sincerely,



cc: Allen Mosher, APPA
Rae McQuade, NAESB

Web Site ◆
www.tapsgroup.org

August 29, 2005

CONTACTS ◆
Roy Thilly, Chairman
Wisconsin Public Power Inc.
1425 Corporate Center Drive
Sun Prairie, WI 53590
608.834.4500
Fax 608.837.0274
rthilly@wppisys.org

◆
Robert McDiarmid
Cindy Bogorad
Spiegel & McDiarmid
1333 New Hampshire Avenue, NW
Washington, DC 20036
202.879.4000
Fax 202.393.2866
robert.mcdiarmid@spiegelmcd.com
cynthia.bogorad@spiegelmcd.com

◆
Deborah Sliz
Morgan Meguire LLC
1225 I Street, NW
Suite 300
Washington, DC 20005
202.661.6192
Fax 202.661.6182
dsliz@morganmeguire.com

◆
Robert Talley
Talley & Associates
2121 K Street, NW
Suite 650
Washington, DC 20037
202.296.4114
Fax 202.296.2409
Tmg1@erols.com

Michehl R. Gent
President & CEO
North American Electric Reliability Council
116-390 Village Boulevard
Princeton, NJ 08540

Re: Inadvertent Interchange Payback

Dear Mike**:**

Thank you for your August 8 response to my July 22 letter, which raised what TAPS members consider to be a fundamental comparability issue.

In our view, inadvertent and imbalance must be treated comparably. In contrast, based on the observation that inadvertent energy is not a bilateral arrangement and takes two forms—primary and secondary—your letter concludes that inadvertent energy is not the same as imbalance and questions whether they can be dealt with on a comparable basis.

In fact, all inadvertent interchange and imbalance energy stem from primary inadvertent. Primary inadvertent is caused by imperfect generation control within a balancing authority. Where a balancing authority is the only entity within its area, its own energy imbalance is its primary inadvertent. Where there is also a TDU within the balancing authority's area, the primary inadvertent is the net of the combined imbalances of the TDU and the balancing authority. While balancing authorities include a calculation for secondary inadvertent based on interconnection frequency, secondary inadvertent simply reflects the impact of primary inadvertent from other balancing authorities.

Providing for in-kind payback for balancing authorities at the same time monetary penalties are imposed for TDU imbalances results in financially non-comparable treatment of the same conduct: imperfect generation control within a control area. Balancing authorities' imbalances are exempt from penalties, while the same imbalances for the TDUs in its area are not, even though the TDUs' imbalances may actually offset the balancing authority's imbalance and so reduce the balancing area's primary inadvertent. The TDU should pay the cost of balancing service, but it should not be penalized when the balancing authority is not penalized for the same conduct. Similarly, the fact that inadvertent energy is not a bilateral arrangement does not justify use of a simple, non-punitive return-in-kind treatment for inadvertent energy while, for tariff customers within a balancing authority, similar imbalances are subject to significant penalties.

Your letter narrowly defines NERC's job as ensuring that NERC standards do not unduly discriminate among the entities to which they apply (i.e., as among all balancing authorities), and concludes that NERC cannot ensure that the standards for balancing authorities are comparable to the treatment of others under tariffs. In contrast, we believe that NERC should not turn a blind eye to fundamental comparability issues when formulating its standards and allow its standards to perpetuate or create obvious discrimination that is not required for technical reliability-based reasons.

We also do not believe NAESB is performing its role if it adopts business standards that discriminate against a minority by reinforcing a clearly non-comparable flow of dollars – market participants subjected to substantially different financial outcomes for substantially identical behavior depending on whether they are balancing authorities. Also, based on discussions with TAPS members who participated in the process, we do not believe it was "practical hurdles … [that] couldn't be crossed" that caused NAESB's IIPTF to recommend no change, but rather a lack of consensus; the IIPTF's July 19 final report concludes (at 5): "With the lack of industry direction for a new 'inadvertent interchange payback' standard the IIPTF has inferred that the industry is satisfied with the requirements within the current NAESB Version 0 Inadvertent Interchange Business Practice Standard." From our perspective, IIPTF's inference that the "industry is satisfied" with the status quo is wrong.

Thus, we reiterate our request that NERC and NAESB address this comparability issue. However, as requested in my July 22 letter, if NERC and NAESB cannot deal with this fundamental comparability issue (because sufficient consensus is not possible), each organization should clearly inform FERC of this problem, identifying the comparability concern that has been raised as a tariff issue that should be addressed by FERC.

Sincerely,

Roy Thilly
TAPS Chair

cc: NAESB WEQ Executive Committee
TAPS Members
Allen Mosher, APPA

TVA Comments on the IIPTF Final Report

TVA participated on the Inadvertent Interchange Payback Task Force (IIPTF) and fully supports the task force's recommendation to continue using the NAESB Version 0 Inadvertent Interchange Payback Standard as the appropriate solution for settling inadvertent interchange.

TVA also believes that the Western Electricity Coordination Council (WECC) Automatic Time Error Control methodology (WATEC) has potential as an alternative means for calculating and settling inadvertent interchange. However, TVA suggests that this be pursued through the North American Reliability Council (NERC) due to its reliability parameters and its interrelationship with the Area Control Error (ACE) Equation.

Comments from WECC on IIPTF Report

-----Original Message-----
From: Mike Wells
To: Veronica Thomason
Sent: Mon Nov 21 16:29:58 2005
Subject: NAESB Wholesale Electric Quadrant Request for Comments - Comments Due November 14, 2005

NAESB,
The comment period on the items listed below elapsed on November 14, 2005 but a work group of the Interchange Scheduling and Accounting Subcommittee of the Western Electricity Coordinating Council (WECC) desires this comment be submitted to NAESB understanding that it is past the deadline.

The WECC ISAS After the Fact Work Group recommends that WECC concur with the NAESB IIPTF recommendation that the Version 0 of the NAESB WEQ Inadvertent Interchange Payback Standards WEQBPS-005-000 not be revised and remain in its present form. Entities throughout WECC believe that the Automated Time Error process is working for us and would like to see it remain as is.

We understand these items will be presented to the Executive Committee at the meeting November 29, 2005.

THANK YOU

Mike Wells
WECC Staff

Wholesale Electric Quadrant

TAB 11

Recommendations for Vote – R04013A – TLR Business Practices

- Recommendation R04013a is attached. The comment period for this request ended November 18. Nine sets of comments were received.
- To approve the recommendation that would separate the TLR version 0 standards and provide only business practices for NAESB, a motion to accept the recommendation would be made by a WEQ EC member, and the resulting vote would need to be 67% of the WEQ EC members (20 of 29 members) and 40% of each segment's EC members.
- The materials in Tab 11 correspond to agenda item 5 for the WEQ EC agenda.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **Business Practices Subcommittee**
Request No.: **R04013A**
Request Title: **Version 0 Business Practices Standards – Development of post-split "Version 0" Transmission Loading Relief Business Practice Standard**

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: Adopt Business Practice Standard for Transmission Loading Relief (TLR) that supports NERC's Reliability Standards and functional model terminology reflective of today's implementation. The NAESB Version 0 TLR Business Practice Standard implements existing business practice as it resides in NERC's current reliability operating policies and planning standards (IRO-006-1).

NAESB and NERC began the task of separating commercial business practices and reliability standards from the NERC Operating Policies to become "Version 0" standards in May of 2004. Although the NAESB proposal and NERC proposal agreed upon the majority of the split, a few areas of proposed division differed. One of those areas was the Transmission Loading Relief procedure, part of NERC Operating Policy 9. On August 2-3, 2004 NERC and NAESB representatives were able to successfully divide the "Version 0" standards with no duplication except for the TLR procedure. The two organizations unanimously agreed for NERC and NAESB to both adopt the TLR standard with the "same language and format" for the "Version 0" format and immediately begin a joint effort to divide the standard. (Please see "NERC/NAESB Collaborative Proposal for Version 0 Business Practice Standards" and "Joint

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Recommendation for Version 0 Business Practices" as found in the August 16, 2004 Joint Interface Committee Meeting Minutes located at http://www.naesb.org/pdf/weq_jic081604dm.pdf.) It was agreed that NAESB would not to file the TLR Business Practice along with the other Version 0 Business Practice Standards included in NAESB Request R04013 with the Federal Energy Regulatory Commission (FERC). However, the group also agreed that the joint effort to divide the standard should produce separate sets of NAESB TLR Business Practice Standards and NERC TLR Reliability Standards by year end 2005. Also, NAESB would file this completed post-split TLR Business Practice Standard with the FERC soon after. The group unanimously agreed that approval of the split standards would retire pre-split "Version 0" TLR standards at both NERC and NAESB.

The Joint NERC/NAESB TLR Subcommittee began meeting on December 9-10, 2004 with the assigned task of separating the TLR standard into reliability and commercial areas, with the reliability portions being assigned to NERC for drafting a reliability standard and the commercial portions being assigned to NAESB for the drafting of a business practice standard. At the December 2004 meeting, the joint task force defined and agreed on a project plan and guiding principles. The group also discussed the steps needed to meet the year end 2005 deadline.

Between January and June 2005, the NERC/NAESB TLR Subcommittee met multiple times (links to minutes for all NERC/NAESB TLR Subcommittee meetings may be found in section 4d of this document) to accomplish their task. On June 1-2, 2005 the TLR Subcommittee unanimously agreed upon the division of TLR as found in "Final Consensus Division of TLR for Version 0 Reliability Practices" (located at http://www.naesb.org/pdf2/weq_tlr060105a1.doc) and as found in "Final Consensus Division of TLR for Version 0 Business Practices" (located at http://www.naesb.org/pdf2/weq_tlr060105a2.doc). (Please note that at this meeting NAESB representatives took a formal vote for the agreed upon division, which was unanimous. In addition, NERC representatives took an informal vote for the agreed upon division which was also unanimous. Please reference the link below for the June 1-2, 2005 minutes.)

The next step for NAESB was the completion of the drafting of the post-split "Version 0" TLR Business Practice Standard from the agreed upon commercial split, in the WEQ Business Practice Subcommittee (BPS). The next step for NERC was to issue a Standards Authorization Request (SAR) for the reliability split and form a drafting team to complete the reliability standard. While preparations were being made at NERC to begin drafting the post-split TLR Reliability Standard, a change was made to IRO-006 (the existing NERC TLR Standard.) The new language was not considered an amended change but merely a correction of a conflict between NERC INT-004, Requirement 5 and IRO-006, Attachment 1 concerning dynamic schedules. The new language on dynamic schedules was sent through NAESB's official standards request process (R05009 "Modify the NAESB Version 0 TLR business practices to remain consistent with the NERC Version 0 TLR reliability standards") and Recommendation R05009 was ratified on October 10, 2005. This language was included in the post-split draft NAESB TLR Business Practice Standard due to its commercial nature.

The NAESB BPS met a total of 8 times between June 14th and October 12th, 2005 to complete the draft business practice standard. Numerous members of the industry, as well as representatives of NERC, participated in the completion of this task. (Links to minutes for the WEQ BPS Subcommittee meetings may be found in section 4d of this document.) The draft post-split "Version 0" NAESB TLR Business Practice Standard was voted out of subcommittee and to the WEQ Executive Committee on October 12, 2005.

RECOMMENDED STANDARDS:

Please see Attachment posted at http://www.naesb.org/pdf2/r04013a_rec_attachment.doc.

4. SUPPORTING DOCUMENTATION

a. Description of Request:

Sections of NERC's existing operating policies and planning standards that contained business practices were identified as suitable for incorporation as NAESB Version 0 Business Practice Standards, including the commercial aspects of the TLR standard. These complementary business practice standards are integral to the operation and enforceability of NERC's reliability standards. The collaborative effort with NERC to prepare a Version 0 foundation of business practices will serve as a cornerstone for future NAESB business practice standards development.

b. Description of Recommendation:

Adopt the TLR Business Practice Standard as recommended.

c. Business Purpose:

Adopt post-split "Version 0" TLR Business Practice Standard that supports NERC's Reliability TLR Standards and functional model terminology reflective of today's implementation.

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

Discussion on this recommendation can be found in the following minutes:

Joint TLR Subcommittee Meeting Minutes	
December 9-10, 2004	http://www.naesb.org/pdf/weq_bps120904fm.doc
February 2-3, 2005	http://www.naesb.org/pdf2/weq_bps020205fm.doc
February 18, 2005	http://www.naesb.org/pdf2/weq_tlr021805fm.doc
February 25, 2005	http://www.naesb.org/pdf2/weq_tlr022505fm.doc
March 30-31, 2005	http://www.naesb.org/pdf2/weq_tlr033005fm.doc

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: Business Practices Subcommittee
Request No.: R04013A
Request Title: Version 0 Business Practices Standards – Development of post-split "Version 0" Transmission Loading Relief Business Practice Standard

April 11, 2005	http://www.naesb.org/pdf2/weq_tlr041105fm.doc
April 27-29, 2005	http://www.naesb.org/pdf2/weq_tlr042805fm.doc
May 9, 2005	http://www.naesb.org/pdf2/weq_tlr050905fm.doc
June 1-2, 2005	http://www.naesb.org/pdf2/weq_tlr060105fm.doc
June 28, 2005	http://www.naesb.org/pdf2/weq_tlr062805dm.doc
WEQ BPS Meeting Minutes	
June 14-15, 2005	http://www.naesb.org/pdf2/weq_bps061405fm.doc
June 29, 2005	http://www.naesb.org/pdf2/weq_bps062905fm.doc
July 20-21, 2005	http://www.naesb.org/pdf2/weq_bps072005fm.doc
August 9-10, 2005	http://www.naesb.org/pdf2/weq_bps080905fm.doc
September 7, 2005	http://www.naesb.org/pdf2/weq_bps090705fm.doc
October 4-5, 2005	http://www.naesb.org/pdf2/weq_bps100405dm.doc
October 12, 2004	http://www.naesb.org/pdf2/weq_bps101205dm.doc

Transmission Loading Relief Business Practices – Eastern Interconnection

Purpose:

This business practice standard defines the requirements necessary to complement transmission loading relief procedures needed for curtailment and reloading of Interchange Transactions to relieve overloads on transmission facilities modeled in the Interchange Distribution Calculator (IDC).

Applicability:

These requirements may be used to relieve congestion on any facility modeled within the IDC or an equivalent interconnection model.

Definitions:

Approval Entity – An entity that has approval rights for an Interchange Transaction Tag. This includes Transmission Service Providers (TSPs), Balancing Authorities (BAs), Purchasing-Selling Entities (PSEs), and Load Serving Entities (LSEs) involved in the Interchange Transaction.

Balancing Authority (BA) – The entity responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time.

Balancing Authority Area (BAA) - An electrical system bounded by Interconnection (tie-line) metering and telemetry, where the Balancing Authority controls (either directly or by contract) generation to maintain its Interchange Schedule with other Balancing Authority Areas and contributes to frequency regulation of the Interconnection.

Bulk Electric System – The electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Constrained Facility – A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its SOL or IROL.

Constrained Flowgate - A Flowgate that is approaching, is at, or is beyond System Operating Limits (SOL) or Interconnection Reliability Operating Limits (IROL).

Constraint – A limitation placed on Interchange Transactions that flow over a Constrained Facility or Flowgate.

Contract Path - A predetermined Transmission Service electrical path between contiguous Transmission Service Providers established for scheduling and commercial settlement purposes that represents the continuous flow of electrical energy between the parties to a transaction.

Curtailment Threshold – The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility Constraint.

Firm Transmission Service - The highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption. Firm Transmission Service includes Firm Point-to-point Transmission Service and Firm Network Integration Transmission Service.

Flowgate – A designated point of the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Generation Shift Factor (GSF) – A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or monitored Flowgate.

Generator-to-Load Distribution Factor (GLDF) - The algebraic sum of a GSF and an LSF to determine to total impact of an Interchange Transaction on an identified transmission facility or monitored Flowgate.

Interchange Distribution Calculator (IDC) – The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific transmission interfaces, which are known as "Flowgates." It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Interchange Transaction - A transaction that crosses one or more Balancing Authorities' boundaries. The planned energy exchange between two adjacent Balancing Authorities.

Interchange Transaction Tag (Tag) – An Interchange Transaction being submitted for implementation according to NERC "Electronic Tagging Functional Specification", version 1.7.095

Interconnection – Any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.

Interconnection Reliability Operating Limit (IROL) – The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of, the System Operating Limit, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

Load Shift Factor (LSF) - A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.

Native Load (NL) - The demand imposed on an electric utility or an entity by the requirements of all customers located within a franchised service territory that the electric utility or entity has statutory or contractual obligation to serve.

NERC – North American Electric Reliability Council

Network Integration (NI) Transmission Service – As specified in the Transmission Service Provider's tariff, service that allows an electric Transmission Customer to integrate, plan, economically dispatch and regulate its network resources in a manner comparable to that in which the transmission owner serves Native Load customers.

Non-Firm Transmission Service - As specified in the Transmission Service Provider's tariff, transmission service that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption, and has less priority than Firm Transmission.

Per Generator Method – A methodology used by the IDC to calculate the portion of parallel flows on any Constrained Facility or Flowgate due to Network Integrated (NI) transmission service customers and service to Native Load (NL) customers for each Balancing Authority.

Point-to-point (PTP) Transmission Service - As specified in the Transmission Service Providers tariff, Transmission Service reserved and/or scheduled between specified points of receipt and delivery.

Purchasing-Selling Entity (PSE) – The entity that purchases or sells and takes title to energy capacity and interconnected operations services. PSE's may be affiliated or unaffiliated merchants and may and may not own generating facilities.

Reliability Coordinator Information System (RCIS)**.** –The system that Reliability Coordinators use to post messages and share operating information in real time.

Reallocation – The process used to totally or partially curtail Transactions during TLR levels 3a, 3b or 5a events to allow Transactions using equal or higher priority to be implemented.

Reliability Area - The collection of generation, transmission, and loads within the boundaries of a Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

Reliability Coordinator (RC) - An entity that provides the security assessment and emergency operations coordination for a group of Balancing Authorities, Transmission Service Providers, and Transmission Operators.

Sink Balancing Authority - The Balancing Authority in which the load (Sink) is located for an Interchange Transaction. (This will also be a receiving Balancing Authority for the resulting Interchange Schedule).

System Operating Limit (SOL) - The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria.

Tie Facility(ies) – The transmission facility(ies) interconnecting Balancing Authority Areas.

Transfer Distribution Factor (TDF) - The portion of an Interchange Transaction, expressed in percent that flows across a transmission facility (Flowgate).

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

Transmission Loading Relief (TLR) - A procedure used in the Eastern Interconnection to relieve potential or actual loading on a Constrained Facility or Flowgate.

Transmission Operator – The entity that operates or directs the operations of transmission facilities.

Transmission Service – Services needed to move energy from a receipt point to a delivery point provided to Transmission Customers by Transmission Service Providers.

Transmission Service Provider (TSP) or Transmission Provider (TP) - The entity that administers the transmission tariff and provides transmission services to qualified Transmission Customers under applicable transmission service agreements.

Business Practice Requirements:

1. General Requirements Regarding use of Interconnection-wide TLR procedures

1.1. **Use of Interconnection-wide TLR procedures.** All Reliability Coordinators shall be obligated to follow the transmission loading relief procedures associated with the appropriate Interconnection-wide TLR procedure for their Interconnection.

1.2. **Use of local procedures.** A Reliability Coordinator shall be allowed to implement a local transmission loading relief or congestion management procedure simultaneously with the Interconnection-wide TLR procedure.

1.2.1. The Reliability Coordinator shall revert back to the Interconnection-wide TLR procedure in the event local procedures do not adequately alleviate the Interconnection Reliability Operating Limits (IROL) or System Operating Limits (SOL) violation.

1.3. **Market-based congestion management or re-dispatch procedures**. Regulatory-approved market-based congestion management or re-dispatch procedures shall be allowed as a supplement to, or substitute for, the Interconnection-wide TLR procedure.

1.3.1. The Reliability Coordinator shall ensure that transactions associated with Point-to-point Transmission Service, Network Integration Transmission Service, and Transmission Service associated with Native Load, having been identified as linked with a Regulatory-approved Market-based congestion management procedure, are protected from curtailment to the extent that the Regulatory-approved Market-based congestion management procedure allows.

1.3.1.1.The Interchange Transaction shall retain its original transmission service priority for purposes of curtailment when the transmission service is not reserved on the Constrained Facility or Flowgate.

1.3.2. The Reliability Coordinator shall revert back to the Interconnection-wide TLR procedure in the event Market-based procedures do not adequately alleviate the IROL or SOL violations.

1.4. **Regional differences.** Regional methods are included in this standard in Appendix D.

1.5. **Commercial notifications.** The Reliability Coordinator shall simultaneously notify all parties affected by the invocation of a local congestion management procedure or the Interconnection-wide TLR procedure, using the notification method as specified by NERC (e.g. – the Reliability Coordinator Information System or successor).

1.6. **Access to procedure logs.** The Reliability Coordinator shall ensure that NERC TLR logs specifying the details associated with the initiation of TLR level 2 or higher and/or the invocation of the Interconnection-wide TLR procedure are available, subject to applicable confidentiality requirements, to all market participants, regardless of the procedure used to achieve that relief.

2. Interchange Transaction Priorities for Use with Interconnection-wide TLR procedures

2.1. **Priority of Interchange Transactions**. The Reliability Coordinator shall recognize the Interchange Transaction priority determined by the Transmission Service reserved as follows:

2.1.1. Priority 0. Next-hour Market Service – NX (if offered by Transmission Service Provider)

2.1.2. Priority 1. Service over secondary receipt and delivery points – NS

2.1.3. Priority 2. Non-Firm Point-to-point Hourly Service – NH

2.1.4. Priority 3. Non-Firm Point-to-point Daily Service – ND

2.1.5. Priority 4. Non-Firm Point-to-point Weekly Service – NW

2.1.6. Priority 5. Non-Firm Point-to-point Monthly Service – NM

2.1.7. Priority 6. Network Integration Transmission Service from sources not designated as network resources – NN

2.1.8. Priority 7. Firm Point-to-point Transmission Service - (F) and Network Integration Transmission Service from Designated Resources – (FN)

2.2. **Interchange Transaction priority when Transmission Service is reserved on the Constrained Facility(ies) or Flowgate(s).** The Reliability Coordinator shall use the following procedure to establish the priority of an Interchange Transaction when Transmission Service is reserved on a contract path that includes the Constrained Facility(ies) or Flowgate(s): (See appendix A for examples)

2.2.1. The Reliability Coordinator shall assign priority to the Interchange Transaction based upon the Transmission Service priority of the Transmission Service link with the Constrained Facility or Flowgate regardless of the Transmission Service priority on the other links along the contract path.

2.2.1.1. The Reliability Coordinator shall consider the entire Interchange Transaction Non-Firm if the transmission link (i.e. a segment on the Contract Path) on the Constrained Facility or Flowgate is Non-Firm Transmission Service, even if other links in the contract path are Firm.

2.2.1.2. The Reliability Coordinator shall consider the entire Interchange Transaction Firm if the transmission link on the Constrained Facility or Flowgate is Firm Transmission Service, even if other links in the contract path are Non-Firm.

2.3. **Interchange Transaction priority when Transmission Service is not reserved on the Constrained Facility(ies) or Flowgate(s).** The Reliability Coordinator shall use the following procedure to establish the priority of an Interchange Transaction when Transmission Service is reserved on a contract path that does not include the Constrained Facility or Flowgate: (See appendix A for examples)

2.3.1. The Reliability Coordinator shall assign priority to the Interchange Transaction based upon the lowest Transmission Service priority of all Transmission Service links along the Contract Path.

2.3.1.1. The Reliability Coordinator shall consider the entire Interchange Transaction Non-Firm if any of the transmission links on the Contract Path are Non-Firm Transmission Service.

2.3.1.2. The Reliability Coordinator shall consider the entire Interchange Transaction Firm if all of the transmission links on the Contract Path are Firm Transmission Service, even if none of the transmission links are on the Constrained Facility or Flowgate, and shall not be curtailed to relieve a Constraint off the Contract Path until all Non-Firm Interchange Transactions that are at or above the Curtailment Threshold have been curtailed.

2.4. **Sub-priorities during Reallocation.** During Reallocation, the Reliability Coordinator shall utilize the following sub-priorities as established in the IDC, listed from highest priority to lowest priority, within each Non-Firm Transmission Service priority for determining how pending Interchange Transactions with equal or higher priority Transmission Service shall be loaded:

2.4.1. Sub-priority S1. Sub-priority S1 shall be assigned to that portion of an Interchange Transaction that is already flowing.

2.4.2. Sub-priority S2. Sub-priority S2 shall be assigned to that portion of an Interchange Transaction that has been curtailed or held by the Interconnection-wide TLR procedure.

2.4.3. Sub-priority S3. Sub-priority S3 shall be assigned to that incremental portion of an already flowing Interchange Transaction that is scheduled to increase from its current hour schedule in the upcoming hour in accordance with its energy profile, or schedules submitted prior to the implementation of the Interconnection-wide TLR procedure.

2.4.4. Sub-priority S4. Sub-priority S4 shall be assigned to a new or revised Interchange Transaction that is submitted after the Interconnection-wide TLR procedure has been declared.

3. Eastern Interconnection Procedure for Physical Curtailment of Interchange Transactions

3.1. **TLR level 1.** When a Reliability Coordinator has initiated a TLR level 1 (Notify all Reliability Coordinators of potential SOL or IROL Violations), the Reliability Coordinator shall take no action against any Interchange Transaction.

3.2. **TLR level 2.** When a Reliability Coordinator has initiated a TLR level 2 (Hold transfers at present level to prevent SOL or IROL Violations), the Reliability Coordinator shall take the following actions:

3.2.1. The Reliability Coordinator should ensure that TLR level 2 is a transient state so that Interchange Transactions are properly initiated according to their transmission reservation priority.

3.2.1.1.The Reliability Coordinator should make best efforts possible to ensure that TLR level 2 does not exceed 30 minutes in duration.

3.2.1.2.If TLR level 2 exceeds 30 minutes in duration, the Reliability Coordinator shall document this action on the NERC TLR log.

3.2.2. The Reliability Coordinator shall hold the implementation of any additional Interchange Transactions using Non-Firm Transmission Service that are at or above the Curtailment Threshold.

3.2.3. The Reliability Coordinator shall allow additional Interchange Transactions that flow across the Constrained Facility or Flowgate to be initiated if their flow reduces the loading on the Constrained Facility or Flowgate or has a Transfer Distribution Factor (TDF) less than the Curtailment Threshold.

3.2.4. The Reliability Coordinator shall allow all Interchange Transactions using Firm Transmission Service to be initiated.

3.2.5. If an Interchange Transaction is identified as a Dynamic Schedule and the Transmission Service is considered Firm according to the constrained path method, then it will not be held by the IDC during TLR level 4 or lower. Adjustments to Dynamic Schedules in accordance with NERC INT-004 R5 will not be held under TLR level 4 or lower.

3.3. **TLR level 3a.** When a Reliability Coordinator has initiated a TLR level 3a (Reallocation of Transmission Service by curtailing Interchange Transactions using Non-Firm Transmission Service to allow Interchange Transactions using higher priority Transmission Service to start), the Reliability Coordinator shall take the following actions:

3.3.1. The Reliability Coordinator shall allow those Interchange Transactions using Firm Transmission Service that have been

submitted prior to the NERC-approved tag submission deadline for Reallocation (*as found in* NERC IRO-006-1, effective date August 8, 2005) to be initiated as scheduled.

3.3.1.1. The Reliability Coordinator shall hold an Interchange Transaction using Firm Transmission Service if the Interchange Transaction is submitted after the NERC-approved tag submission deadline for Reallocation during TLR level 3a, but shall allow the transaction to start in the following hour.

3.3.1.2. Reallocations for Dynamic Schedules are as follows: If an Interchange Transaction is identified as a Dynamic Schedule and the Transmission Service is considered Firm according to the constrained path method, then it will not be held by the IDC during TLR level 4 or lower. Adjustments to Dynamic Schedules in accordance with NERC INT-004 R5 will not be held under TLR level 4 or lower.

3.3.2. The Reliability Coordinator with the constraint shall consider for curtailment those Interchange Transactions using lower priority Non-Firm Transmission Service as specified in Requirement 2, "Interchange Transaction Priorities for use with Interconnection-wide TLR procedures" to allow higher priority Transmission Service schedules to start.

3.3.2.1.The Reliability Coordinator shall consider only those Interchange Transactions that have been submitted prior to the NERC-approved tag submission deadline for Reallocation during TLR level 3a for the upcoming hour.

3.3.2.1.1. Interchange Transactions submitted after this deadline shall be considered for Reallocation for the following hour. This applies to Interchange Transactions using either Non-firm Transmission Service or Firm Transmission Service. If an Interchange Transaction using Firm Transmission Service is submitted after the NERC-approved tag submission deadline and after the TLR is declared, that Transaction shall be held and then allowed to start in the upcoming hour.

3.3.2.2.The Reliability Coordinator shall only consider those Interchange Transactions at or above the Curtailment Threshold for which the Interconnection-wide TLR procedure is called.

3.3.2.3. The Reliability Coordinator shall displace Interchange Transactions utilizing lower priority Transmission Service with Interchange Transactions utilizing higher priority Non-Firm or Firm Transmission Service.

3.3.2.4. The Reliability Coordinator shall not curtail Interchange Transactions using Non-Firm Transmission Service to allow the initiation or increase of another transaction having the same Non-Firm Transmission Service priority.

3.3.2.5.If all Interchange Transactions using Non-Firm Transmission Service have been curtailed and there are additional requests to allow Interchange Transactions using Firm Transmission Service to begin that cannot be accommodated without violating an SOL/IROL, the Reliability Coordinator shall initiate TLR level 4 or level 5a as appropriate.

3.3.2.6.The Reliability Coordinator shall reload curtailed Interchange Transactions prior to starting new or increasing existing Interchange Transactions.

3.3.2.6.1. Interchange Transactions that were submitted prior to the initiation of the Interconnection-wide TLR procedure but were subsequently held from starting because they failed to meet the NERC-approved tag submission deadline for Reallocation during TLR level 3a or were held over from a TLR level 2, shall be considered to have been curtailed and thus would be eligible for reload at the same time as the curtailed Interchange Transaction.

3.3.3. The Reliability Coordinator shall consider for Reallocation and/or reload Interchange Transactions that have been held or curtailed as prescribed in this business practice standard according to their Transmission Service priorities when operating conditions permit.

3.3.3.1.The Reliability Coordinator shall fill available transmission capability by reloading or starting eligible Transactions using the Sub-priorities assigned in Requirements 2.4.1 through 2.4.4. In case all of the transactions in a sub-priority cannot be reloaded, the transactions in that sub-priority shall be loaded based on a pro rata basis by allocating the remaining available transmission capability in proportion to the scheduled amount.

3.3.4. The Reliability Coordinator shall consider for Reallocation Interchange Transactions that meet the NERC-approved tag submission deadline at the start of the following hour.

3.3.5. In considering transactions using Non-Firm Transmission Service for curtailment and/or Reallocation, the Reliability Coordinator shall consider transaction sub-priorities as follows:

3.3.5.1. Interchange Transactions with sub-priority S1 shall be allowed to continue flowing at the lesser of its current hour MW level or the MW level specified in the schedule for the upcoming hour. For calculated values less than zero, zero shall be used.

3.3.5.2.Interchange Transactions with sub-priority S2 shall be allowed to reload to the lesser of its current hour MW level or the MW level specified in the schedule for the upcoming hour. For calculated values less than zero, zero shall be used.

3.3.5.3. Interchange Transactions with sub-priority S3 shall be allowed to increase from its current hour MW level to the MW level specified

in its schedule for the upcoming hour. For calculated values less than zero, zero shall be used.

3.3.5.4. Interchange Transactions with sub-priority S4 shall be allowed to start once all other Interchange Transactions with the same Transmission Service priority submitted prior to the initiation of the Interconnection-wide TLR procedure have been (re-)loaded.

3.4. **TLR level 3b.** When a Reliability Coordinator has initiated a TLR level 3b (curtail Interchange Transactions using Non-Firm Transmission Service arrangements to mitigate a SOL or IROL violation), the Reliability Coordinator shall take the following actions:

3.4.1. The Reliability Coordinator shall allow Interchange Transactions using Firm Transmission Service to start if they are submitted prior to the NERC-approved tag submission deadline during TLR level 3b.

3.4.1.1.The Reliability Coordinator shall only consider those Interchange Transactions at or above the Curtailment Threshold for which the Interconnection-wide TLR procedure is called.

3.4.1.2.Reallocations for Dynamic Schedules are as follows: If an Interchange Transaction is identified as a Dynamic Schedule and the Transmission Service is considered Firm according to the constrained path method, then it will not be held by the IDC during TLR level 4 or lower. Adjustments to Dynamic Schedules in accordance with NERC INT-004 R5 will not be held under TLR level 4 or lower.

3.4.2. To mitigate a SOL or IROL in the current hour, the Reliability Coordinator shall curtail Interchange Transactions using Non-Firm Transmission Service that are at or above the Curtailment Threshold as defined in section 3.10 and use the Interchange Transaction priorities as specified in Requirement 2 "Interchange Transaction Priorities for use with Interconnection-wide TLR procedures."

3.4.3. To continue mitigation of the SOL or IROL for the beginning of the next hour, the Reliability Coordinator shall curtail additional Interchange Transactions using Non-Firm Transmission Service to provide transmission capacity for Interchange Transactions using Firm Transmission Service or Interchange Transaction using higher priority Non-Firm Transmission Service utilizing the Reallocation procedures as specified in Requirement 3.3.

3.4.4. If all Interchange Transactions using Non-Firm Transmission Service have been curtailed and there are additional requests to allow Interchange Transactions using Firm Transmission Service to begin that cannot be accommodated without violating an SOL/IROL, the Reliability Coordinator shall initiate TLR level 4, level 5a, or level 5b as appropriate.

3.5. **TLR level 4.** When a Reliability Coordinator has initiated a TLR level 4 (Reconfigure Transmission), the Reliability Coordinator shall take the following actions:

3.5.1. The Reliability Coordinator shall hold (not implement) all new Interchange Transactions using Non-Firm Transmission Service that are at or above the Curtailment Threshold.

3.5.2. The Reliability Coordinator shall allow Interchange Transactions using Firm Transmission Service to start if they are submitted prior to the NERC-approved tag submission deadline during TLR level 3b.

3.5.2.1.If an Interchange Transaction is identified as a Dynamic Schedule and the Transmission Service is considered Firm according to the constrained path method, then it will not be held by the IDC during TLR level 4 or lower. Adjustments to Dynamic Schedules in accordance with NERC INT-004 R5 will not be held under TLR level 4 or lower.

3.6. **TLR level 5a.** When a Reliability Coordinator has initiated a TLR level 5a, the Reliability Coordinator shall allow additional Interchange Transactions using Firm Transmission Service to be implemented after all Interchange Transactions using Non-Firm Transmission Service have been curtailed. The Reliability Coordinator shall reallocate Transmission Service by curtailing on a pro rata basis Interchange Transactions using Firm Transmission Service to allow additional Interchange Transactions using Firm Transmission Service to start on a pro rata basis. These actions shall be taken in accordance with the NERC-approved tag submission deadline for Reallocation.

3.6.1. The Reliability Coordinator shall only consider those Interchange Transactions at or above the Curtailment Threshold for which the Interconnection-wide TLR procedure is called.

3.6.2. The Reliability Coordinator shall use the following process for reallocation of Interchange Transactions using Firm Transmission Service:

3.6.2.1.The Reliability Coordinator shall assist the Transmission Operator(s) in identifying known re-dispatch options that are available to the Transmission Customer that will mitigate the loading on the Constrained Facilities or Flowgates.

3.6.2.1.1. If such re-dispatch options are deemed insufficient to mitigate loading on the Constrained Facilities or Flowgates, the Reliability Coordinator shall continue to implement these re-dispatch options while simultaneously implementing other actions as described in this requirement.

3.6.2.2.The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility or Flowgate caused by Interchange Transactions utilizing Firm Transmission Service that are at or above the Curtailment Threshold and the Transmission Provider's Native Load and untagged Network Integration Transmission Service, as required by the Transmission Provider's filed tariff and as described

in requirement 3.11, "Parallel flow calculation procedure for reallocating or curtailing Firm Transmission Service."

3.6.2.3.The Reliability Coordinator shall curtail or reallocate Interchange Transactions utilizing Firm Transmission Service and ask for relief from the Transmission Provider's Native Load and untagged Network Integration Transmission Service as identified in requirement 3.6.1.2 to allow the start of additional Interchange Transactions utilizing Firm Transmission Service provided those transactions were submitted in accordance to the NERC-approved tag submission deadline for Reallocation during TLR level 5a.

3.6.2.3.1. The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the Transmission Provider's tariff.

3.6.2.3.2. The Reliability Coordinator will assist the Transmission Provider to ensure that available re-dispatch options will continue to be implemented.

3.7. **TLR level 5b.** When a Reliability Coordinator has initiated a TLR level 5b (curtail Interchange Transactions using Firm Transmission Service to mitigate a SOL or IROL violation), the Reliability Coordinator shall take the following actions:

3.7.1. The Reliability Coordinator shall use the following process for curtailment of Interchange Transactions using Firm Transmission Service:

3.7.1.1.The Reliability Coordinator shall assist the Transmission Operator(s) in identifying those known re-dispatch options that are available to the Transmission Customer that will mitigate the loading on the Constrained Facilities or Flowgates.

3.7.1.1.1. If such re-dispatch options are deemed insufficient to mitigate loading on the Constrained Facilities or Flowgates, the Reliability Coordinator shall continue to implement these re-dispatch options while simultaneously implementing other actions as described in this requirement.

3.7.1.2.The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility or Flowgate caused by Interchange Transactions utilizing Firm Transmission Service that are at or above the Curtailment Threshold and the Transmission Provider's Native Load and untagged Network Integration Transmission Service, as required by the Transmission Provider's filed tariff and as described in Requirement 3.11, "Parallel flow calculation procedure for reallocating or curtailing Firm Transmission Service."

3.7.1.3.The Reliability Coordinator shall curtail Firm Interchange Transactions utilizing Firm Transmission Service and shall ask for

relief from the Transmission Provider's Native Load and untagged Network Integration Transmission Service as calculated in requirement 3.7.1.2 until the SOL or IROL violation has been mitigated.

3.7.1.3.1. The Reliability Coordinator will assist the Transmission Provider to ensure that available re-dispatch options will continue to be implemented.

3.7.1.3.2. The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Native Load and untagged Network Integration Transmission Service customers if such curtailments are required by the Transmission Provider's tariff.

3.8. **TLR level 6.** When a Reliability Coordinator initiates a TLR level 6 (emergency conditions), all parties shall comply with the Reliability Coordinator's (s') requests to return the system to a safe and stable condition.

3.9. **TLR level 0.** The Reliability Coordinator shall notify all affected parties when the Reliability Coordinator has returned the system to TLR level 0.

3.9.1. The Reliability Coordinator shall re-establish Interchange Transactions at its discretion. Those with the highest transmission priorities shall be re-established first, as described in requirement 2.1, as practicable.

3.10. **Curtailment Threshold.** The Curtailment Threshold for the Eastern Interconnection shall be 0.05 (5%).

3.11. **Parallel flow calculation procedure for reallocating or curtailing Firm Transmission Service.** The Reliability Coordinator initiating a curtailment shall identify for curtailment all firm transmission services (i.e. PTP, NI, and service to NL) that contribute to the flow on any Constrained Facility or Flowgate by an amount greater than or equal to the Curtailment Threshold on a pro rata basis.

3.11.1. The Reliability Coordinator shall use Transfer Distribution Factors (TDF's) to calculate the portion of parallel flows on any Constrained Facility or Flowgate due to Interchange Transactions using Firm Transmission Service.

3.11.1.1. Only those Interchange Transactions with TDF's greater than or equal to the Curtailment Threshold shall be considered.

3.11.2. The Reliability Coordinator shall use the Per Generator Method to calculate the portion of parallel flows on any Constrained Facility or Flowgates due to Network Integrated (NI) transmission service customers and service to Native Load (NL) customers for each Balancing Authority (See appendix B for examples).

3.11.2.1. The Reliability Coordinator shall assign the amount of Constrained Facility or Flowgate relief that must be achieved by each NI transmission service or NL customers within a given Balancing Authority.

3.11.2.1.1. For each NI transmission service or NL customer, the Reliability Coordinator shall determine the amount of flow contributing to the Constrained Facility or Flowgate from those generators assigned to that customer using Generator-to-Load Distribution Factors (GLDFs) for those generators.

3.11.2.1.2. The GLDF for each generator shall determine the impact that generator has on the Constrained Facility or Flowgate.

3.11.2.1.3. The sum of the contributions to the Constrained Facility or Flowgate from all generators assigned to the NI transmission service or NL customer shall be the amount of relief assigned to that customer.

3.11.2.1.4. The Reliability Coordinator shall not specify how the reduction will be achieved.

3.11.2.2. GLDFs shall be calculated for each NI transmission service and NL customer as the Generation Shift Factors (GSFs) of the NI transmission service or NL customer's assigned generation minus its Load Shift Factors (LSFs).

3.11.2.2.1. GSFs shall be calculated from a single bus in the study case.

3.11.2.2.2. LSFs shall be calculated by scaling load.

3.11.2.2.3. The GLDFs must be greater than or equal to the Curtailment Threshold to be considered.

3.11.2.2.4. GLDFs whose contributions are counter to the constraint (i.e. counter flow) shall be ignored for the purposes of the calculation.

3.11.2.3. Each generator shall be assigned to a given NI transmission service or NL customer within a Balancing Authority Area for the purposes of calculating their contribution to a given constraint. Exceptions may include special cases where generators are only included for case modeling purposes.

3.11.2.4. For a given generator bus, all generators modeled at that bus shall be assumed online and operating at their maximum MVA value except as noted otherwise in this procedure.

3.11.2.4.1. At the time of calculation, daily operating reliability information will be used to update the calculation for transmission line outages, generator outage or derate information, and daily load forecasts as appropriate.

3.11.2.4.2. Only those generator buses whose aggregate modeled capacity exceeds 20MW shall be considered. Generator buses whose aggregate modeled capacity does not exceed 20MW shall be excluded.

3.11.2.5. Generators shall be assigned to a given NI transmission service or NL customer based upon the customer's controlling interest in the facility and may include partial facilities or facilities from Balancing Authority Areas external to the customer's host Balancing Authority.

3.11.2.6. If the total amount of generation from the generation facilities assigned to a given NI transmission service or NL customer exceed the total load for that customer, the generation shall be scaled down to match that customer's total load.

3.11.2.7. If the total amount of generation from the generation facilities assigned to a given NI transmission service or NL customer is less than the total load for that customer, it shall be assumed that the imports necessary to meet total load are being scheduled on Point-to-point Transmission Service. Generation shall not be scaled to meet load in this instance.

3.11.2.8. All NI transmission service and NL customers in the Eastern Interconnection, working with their respective Balancing Authorities, shall be obligated to achieve the amount of relief assigned to them by the Reliability Coordinator via the Per Generator Method.

Appendix A

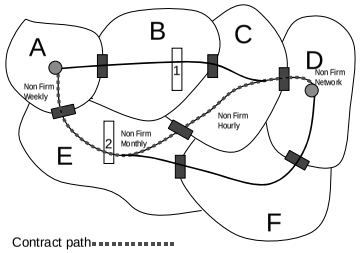
Examples of On-Path and Off-Path Mitigation

This section explains, by example, the obligations of the Transmission Service Providers on and off the contract path when calling for Transmission Loading Relief. When Reallocating or curtailing Interchange Transactions using Firm Transmission Service under TLR level 5a or 5b, the Transmission Service Providers may be obligated to perform comparable curtailments of its Transmission Service to Network Integration and Native Load customers.

Scenario:

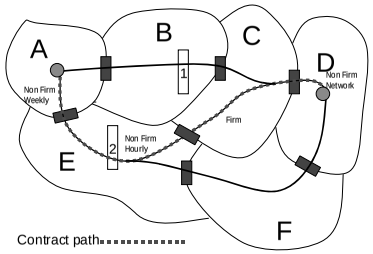
- Interchange Transaction arranged from system A to system D, and assumed to be at or above the Curtailment Threshold
- Contract path is A-E-C-D (except as noted)
- Locations 1 and 2 denote Constraints

Case 1: E is a Non-Firm monthly path, C is Non-Firm hourly; E has Constraint at #2.



- E may call Reliability Coordinator for TLR Procedure to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action **as though it was being served by Non-Firm monthly Point-to-point Transmission Service**, even though it was using Non-Firm hourly Point-to-point Transmission Service from C. That is, it takes on the priority of the link with the Constrained Facility or Flowgate along the Contract Path. (See section 2.2.)

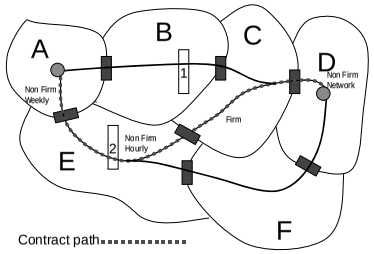
Case 2: E is a Non-Firm hourly path, C is Firm; E has Constraint at #2.



- Although C is providing Firm Transmission Service, the Constraint is not on C's system; therefore, E is not obligated to treat the Interchange Transaction as though it was being served by Firm Transmission Service.
- E may call Reliability Coordinator for TLR Procedure to relieve overload at Constraint #2.

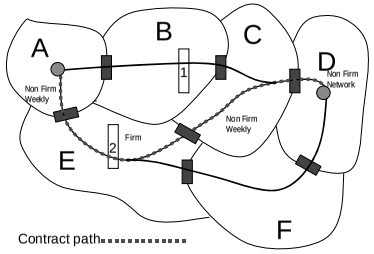
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-Firm hourly Point-to-point Transmission Service, even though it was using Firm Transmission Service from C. That is, when the Constraint is on the Contract Path, the Interchange Transaction takes on the priority of the link with the Constrained Facility or Flowgate. (See section 2.2.)

Case 3: E is a Non-Firm hourly path, C is Firm, B has Constraint at #1.



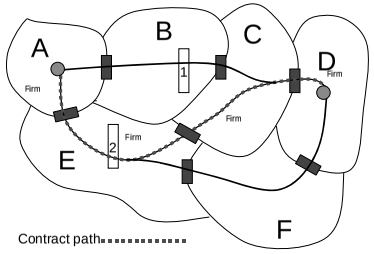
- B may call Reliability Coordinator for TLR Procedure to relieve overload at Constraint #1.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-Firm hourly Transmission Service, even if it was using Firm Transmission Service elsewhere on the path. When the Constraint is off the Contract Path, the Interchange Transaction takes on the lowest priority reserved on the Contract path. (See section 2.3.)

Case 4: E is a Firm path; A, D, and C are Non-Firm; E has Constraint at #2.



- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may then call Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-Firm Transmission Service first.
- E is obligated to try to reconfigure transmission to mitigate Constraint #2 in E before E may curtail the Interchange Transaction as ordered by the TLR. (See Section 2.2)

Case 5: The entire path (A-E-C-D) is Firm; E has Constraint at #2.

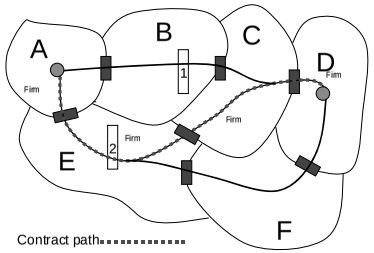


- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may call Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-Firm Transmission Service first.
- E is obligated to curtail Interchange Transactions using Non-Firm Transmission Service, and then reconfigure transmission on its system, or, if there is an agreement in place, arrange for reconfiguration or other congestion management options on

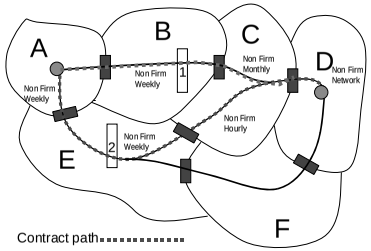
another system, to mitigate Constraint #2 in E before the Firm A-D transaction is curtailed. (See section 2.2.)

- A, C, D, may be requested by E to try to reconfigure transmission to mitigate Constraint #2 in E at E's expense. (See section 2.2.)

Case 6: The entire path (A-E-C-D) is Firm; B has Constraint at #1.



- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- B may call Reliability Coordinator for TLR Procedure for all *Non-Firm* Interchange Transactions that contribute to the overload at Constraint #1.
- Following the curtailment of all Non-Firm Interchange Transactions, the Reliability Coordinator(s) will determine which Transmission Operator(s) will reconfigure their transmission, if possible, to mitigate Constraint #1. (See section 2.3.)
- A-D transaction may be curtailed as a result. However, the A-D transaction is treated as a Firm Interchange Transaction and will be curtailed only after Non-Firm Interchange Transactions. (Note: This means that the Firm Contract Path is respected by all parties, including those not on the Contract Path.) (See section 2.3.)



Case 7: Two A-to-D transactions using A-B-C-D and A-E-C-D; A and B are Non-Firm; B has Constraint at #1

- B is not obligated to reconfigure transmission to mitigate Constraint at #1. (See section 2.2.)
- B may call for TLR Procedure to relieve overload at Constraint #1.
- If both A – D Interchange Transactions have the same TDF across Constraint #1, then they both are subject to curtailment. However, Interchange Transaction A – D using the A-B-C-D path is assigned a higher priority (priority NW on B), and would not be curtailed until after the Interchange Transaction using the path A-E-C-D (priority NH on the Contract Path as observed by B who is off the Contract Path).

Appendix B

Example Calculations of the Per Generator Method

Example 1: The Per Generator Method Calculation

An example of calculating Firm transaction curtailments using the Per Generator Method is provided in this section, assuming that the Constrained Flowgate is #3006 (Eau Claire-Arpin 345 kV circuit). The Generator-to-Load Distribution Factors (GLDFs) for this Flowgate are presented in Table B-1. In this example, a total Firm (PTP and tagged NI transactions) contribution of 708.85 MW is assumed to be given by the IDC.

From Table B-1, the untagged NI/NL contributions of all Balancing Authority Areas that impact the Constrained Facility or Flowgate are listed below:

ALTE = 27.0 MW

ALTW = 41.1 MW

NSP = 33.1 MW

WPS = 26.2 MW

Total NL & untagged NI contribution = 127.4 MW

Total Firm (PTP and NI/NL) contribution = 127.4 MW + 708.85 MW = 836.25 MW

NL & NI portion of total Firm contribution = 127.4/836.25 = 15.2%

PTP and tagged NI portion of total Firm contribution = 708.85/836.25 = 84.47%

Allocation of relief of the Constrained Facility or Flowgate to each Balancing Authority Area with impactive untagged NI/NL contribution is given below:

ALTE = 27.0 /127.4 x 0.152 = 3.2%

ALTW = 41.1 /127.4 x 0.152 = 4.9%

NSP = 33.1 /127.4 x 0.152 = 3.9%

WPS = 26.2 /127.4 x 0.152 = 3.1%

Assume that 50 MW of relief is needed. Then those Balancing Authority Areas that impact NI/NL contribution and Firm Transmission Service are responsible for the providing the following amounts of Flowgate relief:

Relief provided by removing Firm PTP and tagged NI = 0.845 x 50 = 42.25 MW

Relief provided by removing NL and untagged NI contributions ALTE = 0.032 x 50 = 1.60 MW

Relief provided by removing NL and untagged NI contributions ALTW = 0.049 x 50 = 2.45 MW

Relief provided by removing NL and untagged NI contributions NSP = 0.039 x 50 = 1.95 MW

Relief provided by removing NL and untagged NI contributions WPS = 0.031 x 50 = 1.55 MW

Table B-1

Native Load Responsibilities

Flowgate #: 3006 **Flowgate Name: EAU CLAIRE-ARPIN 345 KV**

Common Name	Generator Reference System	Generator Shift Factor (GSF)	Percent Assigned	GLDF Gen to Load Factor	Pmax (MW)	Energy on Flowgate
ALTE #364	Avail Assigned Gen: 1,514 Load Level: 1,796 Scaling: 1.000	ALTE_LD Load Shift Factor: -0.097	.	.	.	.
NED G1 13.8--1 CA=ALTE	39000_NED_G1	0.022	100	.1195	113.0	13.5
NED G2 13.8--2 CA=ALTE	39001_NED_G2	0.022	100	.1195	113.0	13.5
Summary	.	.	.	.	.	**27.0**
WPS #366	Avail Assigned Gen: 1,691 Load Level: 1,910 Scaling: 1.000	WPS_LD Load Shift Factor: -0.193	.	.	.	.
COL G1 22.0--1 CA=ALTE	39152_COL_G1	-0.094	32	.0993	525.0	16.6
COL G2 22.0--2 CA=ALTE	39153_COL_G2	-0.094	32	.0993	525.0	16.6
EDG G4 22.0--4 CA=ALTE	39207_EDG_G4	-0.118	32	.0752	331.0	7.9
Summary	.	.	.	.	.	**41.1**
NSP #623	Avail Assigned Gen: 8,492 Load Level: 8,484 Scaling: 0.999	NSP_LD Load Shift Factor: 0.206	.	.	.	.
WHEATON5 161--1 CA=NSP	61870_WHEATO	0.298	100	.0919	55.0	5.0
WHEATON5 161--2 CA=NSP	61870_WHEATO	0.298	100	.0919	63.0	5.8
WHEATON5 161--3 CA=NSP	61870_WHEATO	0.298	100	.0919	55.0	5.0
WHEATON5 161--4 CA=NSP	61870_WHEATO	0.298	100	.0919	55.0	5.0
WHEATON5 161--5 CA=NSP	61871_WHEATO	0.293	100	.0874	57.0	5.0
WHEATON5 161--6 CA=NSP	61871_WHEATO	0.293	100	.0874	57.0	5.0
WISSOTAG69.0--1 CA=NSP	69168_WISSOT	0.266	100	.0601	37.0	2.2
Summary	.	.	.	.	.	**33.1**

Common Name	Generator Reference System	Generator Shift Factor (GSF)	Percent Assigned	GLDF Gen to Load Factor	Pmax (MW)	Energy on Flowgate
ALTW #631	Avail Assigned Gen: 2,337 Load Level: 3,640 Scaling: 1.000	ALTW_LD Load Shift Factor: 0.065	.	.	.	.
FOXLK53G13.8--3 CA=ALTW	62016_FOXLK5	0.147	100	.0819	88.5	7.3
LANS5 4G22.0--4 CA=ALTW	62057_LANS5_	0.116	100	.0506	277.0	14.0
LANS5 3G22.0--3 CA=ALTW	62058_LANS5_	0.116	100	.0505	35.8	1.8
FAIRMONT69.0--3 CA=ALTW	65816_FAIRMO	0.151	100	.0857	5.0	0.4
FAIRMONT69.0--4 CA=ALTW	65816_FAIRMO	0.151	100	.0857	6.0	0.5
FAIRMONT69.0--5 CA=ALTW	65816_FAIRMO	0.151	100	.0857	12.0	1.0
FAIRMONT69.0--6 CA=ALTW	65816_FAIRMO	0.151	100	.0857	7.0	0.6
FAIRMONT69.0--7 CA=ALTW	65816_FAIRMO	0.151	100	.0857	6.5	0.6
Summary	.	.	.	.	.	**26.2**
.	.	.	.	.	.	.
TOTAL Summary	.	.	.	.	.	**127.4**

Example 2: Use of Per Generator Method while Simultaneously Curtailing Transmission Service

An example of the output of the IDC calculation of curtailment of Firm Transmission Service is provided below for the specific Constrained Facility or Flowgate identified in the NERC Book of Flowgates as Flowgate 1368. In this example, a total Firm PTP and tagged NI contribution to the Constrained Facility or Flowgate, as calculated by the IDC, is assumed to be 21.8 MW.

The Table B-2 below presents a summary of each Balancing Authority's responsibility to provide relief to the Constrained Facility or Flowgate due to its untagged NI Transmission Service and service to NL contribution to the Constrained Facility or Flowgate. In this example, Balancing Authority LAGN would be requested to curtail 17.3 MW of its total of 401.1 MW of flow contribution on the Constrained Facility or Flowgate.

In summary, Interchange Transactions would be curtailed by a total of 21.8 MW and untagged NI Transmission Service and service to NL would be curtailed by a total of 178.2 MW by the five Balancing Authorities identified in the table. These curtailments would provide a total of 200.0 MW of relief to the Constrained Facility or Flowgate.

Table B-2

Sink Reliability Coordinator	*Service Point*	*Scaled P Max*	*Flowgate untagged NI &NL MW*	*Current untagged NI &NL Relief*	*untagged NI &NL Responsibility*		*untagged NI &NL Responsibility Acknowledgement*	
					Inc/Dec	*Current Hr*	*Acknowledge Time*	*Total MW Resp.*
EES	EES	8429.7	2991.4	0.0	128.9	128.9	13:44	128.9
EES	LAGN	1514.0	718.6	0.0	31.0	31.0	13:44	31.0
SOCO	SOCO	5089.2	401.1	0.0	17.3	17.3	13:44	17.3
SWPP	CLEC	235.7	18.0	0.0	0.8	0.8	13:42	0.8
SWPP	LEPA	22.8	4.1	0.0	0.2	0.2	13:42	0.2
Total		**15291.4**	**4133.2**	**0.0**	**178.2**	**178.2**		**178.2**

785

Appendix C

Transaction Curtailment Formula

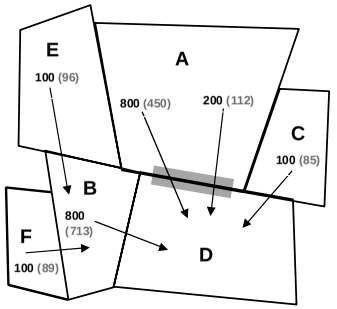
790 **Example**

This example is based on the premise that a transaction should be curtailed in proportion to its Transfer Distribution Factor (TDF) on the Constraints. Its effect on the interface is a combination of its size in MW and its effect based on its distribution factor.

Column	*Description*
1. Initial Transaction	Interchange Transaction before the TLR Procedure is implemented.
2. Distribution Factor	Proportional effect of the Transaction over the constrained interface due to the physical arrangement and impedance of the transmission system.
3. Impact on the Interface	Result of multiplying the Transaction MW by the distribution factor. This yields the MW that flow through the constrained interface from the Transaction. Performing this calculation for each Transaction yields the total flow through the constrained interface from all the Interchange Transactions. In this case, 760 MW.
4. Impact Weighting Factor	"Normalization" of the total of the Distribution Factors in Column 2. Calculated by dividing the Distribution Factor for each Transaction by the total of the Distribution Factors.
5. Weighted Maximum Interface Reduction	Multiplying the Impact on the Interface from each Transaction by its Impact Weighting Factor yields a new proportion that is a combination of the MW Impact on the Interface and the Distribution Factor.
6. Interface Reduction	Multiplying the amount needed to reduce the flow over the constrained interface (280 MW) by the normalization of the Weighted Maximum Interface Reduction yields the actual MW reduction that each Transaction must *contribute* to achieve the total reduction.
7. Transaction Reduction	Divide by the Distribution Factor to see how much the Transaction must be reduced to yield result we calculated in Column 7. Note that the reductions for the first two Interchange Transactions (A-D (1) and A-D (2) are in

	proportion to their size since their distribution factors are equal.
8. New Transaction Amount	Subtracting the Transaction Reduction from the Initial Transaction yields the New Transaction Amount.
9. Adjusted Impact on Interface	A check to ensure the new constrained interface MW flow has been reduced to the target amount.

	Allocation based on Weighted Impact								
	1	2	3	4	5	6	7	8	9
Transaction ID	Initial Transaction	Distribution Factor	(1)*(2) Impact On Interface	(2)/(2TOT) Impact weighting factor	(3)*(4) Weighted Max Interface Reduction	(5)*(Relief Requested) /(5 Tot) Interface Reduction	(6)/(2) Transaction Reduction	(1)-(7) New Transaction Amount	(8)*(2) Adjusted Impact On Interface
Example 1									
A-D(1)	800	0.6	480	0.34	164.57	209.73	349.54	450.46	270.27
A-D(2)	200	0.6	120	0.34	41.14	52.43	87.39	112.61	67.57
B-D	800	0.15	120	0.09	10.29	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.11	2.29	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.03	0.14	0.18	3.64	96.36	4.82
F-B	100	0.15	15	0.09	1.29	1.64	10.92	89.08	13.36
	2100	**1.75**	**760**		**219.71**	**280.00**	**553.45**	**1546.55**	**480.00**
Example 2									
A-D(1)	1000	0.6	600	0.52	313.04	262.16	436.93	563.07	337.84
B-D	800	0.15	120	0.13	15.65	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.17	3.48	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.04	0.22	0.18	3.64	96.36	4.82
F-B	100	0.15	15	0.13	1.96	1.64	10.92	89.08	13.36
	2100	**1.15**	**760**		**334.35**	**280.00**	**553.45**	**1546.55**	**480.00**
Example 3									
A-D(1A)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1B)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1C)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1D)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(2)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
B-D	800	0.15	120	0.04	5.07	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.06	1.13	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.01	0.07	0.18	3.64	96.36	4.82
F-B	100	0.15	15	0.04	0.63	1.64	10.92	89.08	13.36
	2100	**3.55**	**760**		**108.31**	**280.00**	**553.45**	**1546.55**	**480.00**



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Appendix D

PJM/Midwest ISO, Inc. – Enhanced Congestion Management Method (Curtailment/Reload/Reallocation)

Organization

The Balancing Authority participants of:

- Midwest ISO, Inc. (Hereafter referred to as MISO)
- PJM Interconnection, L.L.C. (Hereafter referred to as PJM)

Business Practice

This methodology implements a Multi-Balancing Authority Energy Market, simplifies transaction information requirements for market participants, and allows for a means of providing Reliability Coordinators with appropriate information for security analysis and curtailments/reloads/reallocations and redispatch requirements.

To accommodate a Multi-Balancing Authority Energy Market, this methodology provides for regional differences from the NERC and NAESB specific standards listed below.

This methodology also applies in the event that the above Balancing Authorities are combined into fewer Balancing Authorities or into one Balancing Authority. This methodology is required to realize the benefits of a LMP market operation while increasing the level of granularity of information provided to the NAESB and NERC Transmission Loading Relief standards.. The concepts contained within the PJM/MISO paper, "Managing Congestion to Address Seams," (see footnote 1) meet the requirements specified in this standard, its related appendices, and NERC Standards.

The processes proposed in this methodology affect the following specific sections:

- **Appendix E "How the IDC Handles Reallocation" of NERC IRO-006-1**, (Effective date of standard August 8, 2005)
- **Appendix E "Timing Requirements (IDC Calculations and Reporting Requirements" of NERC IRO-006-1**

Appendix C "Transaction Curtailment Formula" of this document_Section 6 "Interchange Transaction Reallocation During TLR Levels 3a and 5a"of NERC IRO-006-1, For the purposes of clarity, this methodology describes many actions as those of the "RTO." It should be noted that "RTO" refers to the market-operating entity in which the subject Balancing Authorities participate.

Assignment of Sub-Priorities

Requirements

- Requirements 3.3 and 3.6 of this document and as found in NERC IRO-006-1, Appendix E

Explanation

The "IDC Calculations and Reporting Requirements" section of NERC IRO-006-1, Appendix E "Timing Requirements" states that "In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status."

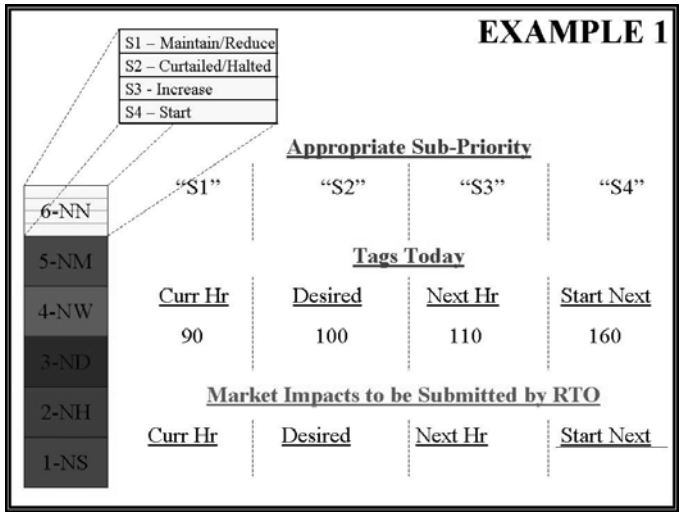
The RTO shall use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List"[1] that is associated with the operation of the RTO market. This energy is identified as "market flow".

These market flow impacts for current hour and next hour shall be separated into their appropriate priorities[2] and provided to the IDC by the RTO. The market flows shall then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional "tags", the impacts and their desired levels shall be provided to the IDC for current hour and next hour. Therefore, the RTO, for the purposes of reallocation, shall be assigned by the NERC IDC a sub-priority (S1 thru S4) to these market flow impacts, using the same parameters as would be used if the impacts were in fact tagged transactions — as detailed in NERC IRO-006-1, Appendix E "How the IDC Handles Reallocation". (See example 1 below).

[1] The RTO will conduct sensitivity studies to determine which external Flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the Balancing Authorities that exist today in the IDC). The RTO will perform the 4 studies as described in the MISO/PJM Paper "Managing Congestion to Address Seams" White Paper (Version 3.2, May 16, 2003, located on the NAESB website at http://www.naesb.org/pdf2/weq_bps101205w3.pdf) to determine which external Flowgates the RTO will monitor and help control. An external Flowgate selected by one of these studies will be considered a coordinated Flowgate (CF).

[2] See the PJM/MISO Paper "Managing Congestion to Address Seams" for details on how these priorities will be assigned



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Pro Rata Curtailment of Non-Firm Market Flow Impacts

Requirements

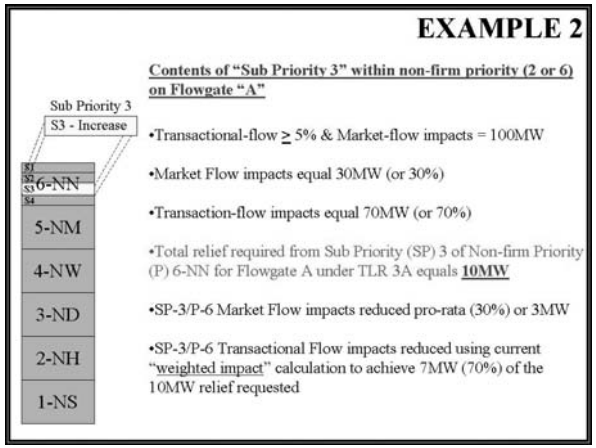
- **Appendix C of this document** "Transaction Curtailment Formula"

Explanation

860 Appendix C of this document "Transaction Curtailment Formula" details the formula used to apply a weighted impact to each Non-Firm tagged transaction (Priorities 1 thru 6) for the purposes of curtailment by the IDC. For the purpose of curtailment, the non-firm market flow impacts (Priorities 1 thru 6) submitted to the IDC by the RTO shall be curtailed pro rata as is done for Interchange Transactions using Firm Transmission
865 Service. This method shall be used, because several of the values needed to assign a weighted impact using the process listed in Appendix C of this document "Transaction Curtailment Formula" will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- 870 Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

875 While the Non-Firm market flow impacts submitted to the IDC would be curtailed pro rata under this methodology, the impacting Non-Firm tagged transactions could still use the existing processes to assign the weighted impact value. Example 2 (below) illustrates how this would be accomplished.



NNL Calculation

Requirements

- **Requirement 3.11 "Parallel flow calculation procedure of reallocating or curtailing Firm Transmission Service" of this document** 'Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service"
- **NERC "Parallel Flow Calculation Procedure Reference Document", version 1 – section C** (Calculation Method), approved November 16, 2000, as found in the NERC Operating Manual.

Explanation

Requirement 3.11 of this document and the NERC "Parallel Flow Calculation Procedure Reference Document", version 1 – section C (Calculation Method)**,** approved November 16, 2000, as found in the NERC Operating Manual**,** currently require that the "Per Generator Method Without Counter Flow" (see footnote 1, PJM/MISO "Managing Congestion at the Seams" White Paper) methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each Balancing Authority.

The RTO shall use a "Market Flow Calculation" methodology to calculate the portion of parallel flows on all facilities included in the RTO's "Coordinated Flowgate List"[3] due to NI service or service to NL of each Balancing Authority.

[3] The RTO will conduct sensitivity studies to determine which external Flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the balancing authorities that exist today in the IDC). The RTO shall perform the four studies (described in the MISO/PJM paper "Managing Congestion to Address Seams," Version 3.2) to determine which external Flowgates the RTO shall monitor and help control. An external Flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).

The "Market Flow Calculation" differs from the Per Generator Method in the following ways:

- The contribution from all market area generators shall be taken into account.
- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The market flow calculations shall use all positively impacting flows down to 0% with no threshold. Counter flows shall not be included in the market flow calculation.
- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the market flow calculation evolves into a methodology very similar the "Per Generator Method" method, while providing granularity on the order of the most granular method developed by the NERC IDC Granularity Task Force. Counter flows are also calculated and tracked in order to account for and recognize that either the positive market flows may be reduced or counter flows may be increased to provide appropriate relief on a Flowgate. Under this methodology, the use of real-time values in concert with the market flow calculation effectively implements the most accurate and detailed method of the six IDC granularity options[4] considered by the NERC IDC Granularity Task Force.

Units assigned to serve a market area's load do not need to reside within the RTO's market area footprint to be considered in the market flow calculation. However, units outside of the RTO's market area shall not be considered when those units have tags associated with their transfers.

These NNL values shall be provided to the IDC to be included and represented with the calculated NNL values of all non-RTO Balancing Authorities for the purposes identifying and obtaining required NNL relief across a Flowgate in congestion under a TLR Level 5A/5B.

5% Curtailment Threshold

Requirements

- **Requirements 3.3.2.2, 3.4.1.1, and 3.6.1 of this document.**
- **Requirement 3.10 "Curtailment Threshold" of this document.**

[4] The NERC IDC Granularity Task Force drafted "White Paper on the Future of Congestion Management", draft version 2.1, completed June of 2004 (located on the NAESB website at http://www.naesb.org/pdf/weq_bps120904a3.doc). Although the task force originally discussed six options for granularity, three options were included in the paper as possible options.

Explanation

Requirements 3.3.2.2, 3.4.1.1, and 3.6.1 of this document state the following: "The Reliability Coordinator shall only consider those Interchange Transactions at or above the Curtailment Threshold for which the Interconnection-wide TLR procedure is called.

The Curtailment Threshold stated in requirement 3.10 is "5%".

The RTO intends to use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List"[5] that is associated with the operation of the RTO market. This energy is identified as "Market Flow".

The RTO intends to provide to the IDC any market flows with an impact of greater than 0% on a coordinated Flowgate. These market flows shall be represented and made available for curtailment under the appropriate TLR Levels. Hence, for the purposes of curtailment and reallocation, the RTO shall observe an impact threshold of 0% instead of 5% for its market flows across any Flowgate in the RTO Coordinated Flowgate List (see footnote 1).

The reason for this lower threshold is because of the size and scope of a large non-tagged energy market, such as the Multi-Balancing Authority market, and an impact of less than 5% on a Flowgate could still represent a large amount of the total capacity of that Flowgate. Therefore, to limit the Curtailment Threshold on these market flows to 5% could result in a Reliability Coordinator's inability to obtain the amount of relief that is needed to prevent the Flowgate from exceeding its operating limits.

Below is an example of how a market flow curtailment threshold of less than 5% could substantially contribute to congestion on a Flowgate:

Example:

- Energy market flows of 1,000 MW impact Flowgate A by 4% — or 40 MW
- Flowgate A operating limit is 100 MW
- Fully 40% of the flow across Flowgate A is not identified and represented in the IDC, and therefore not available for curtailment under the TLR process.

Current Operating Reliability

There are no reliability implications from this regional difference.

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[5] The RTO shall conduct sensitivity studies to determine which external Flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the control areas that exist today in the IDC). The RTO shall perform the 4 studies (described in the MISO/PJM "Managing Congestion to Address Seams" Whitepaper Version 3.2) to determine which external Flowgates the RTO will monitor and help control. An external Flowgate selected by one of these studies will be considered a coordinated Flowgate (CF).

From: Voeck, Julie

Sent: Tuesday, November 15, 2005 11:48 PM

Subject: NAESB TLR Business Practice Standard – American Transmission Company Comments

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1. In Final Consensus Division of TLR for Version 0 Reliability Practices - June 1, 2005 (http://www.naesb.org/pdf2/weq_tlr060105a1.doc),

Appendix A: Transaction Management and Curtailment Process

Chart still has Operating Security Limit (OSL). This should be eliminated.

There is a need for clarification of the processes under SOL and IROL. To distinguish between these two, recommendation is that two sub-charts are created:

IROL Transaction Management and Curtailment Process

SOL Transaction Management and Curtailment process

They are somewhat similar but different. The main difference comes from whether it is a

local or wide area problem. In addition, time reporting requirement. This statement will

lead to the next comment:

2. Under **SOL or IROL, what is the time requirement** to return the system to a reliable state (if in violation)? Furthermore, what is the **reporting requirement** that System Operator should respect if either violating SOL or IROL. This is still vaguely defined. IROL is no later then 30 minutes System Operator must returned the system to a reliable state, otherwise reporting to NERC will follow. What about SOL?

3. Curtailment Threshold for the Eastern Interconnection shall be 0.05 (5%).

Comment: If there are any exceptions to this (waiver for a specific lower threshold application is received and approved by group), then they should be listed to eliminate confusions (e.g. ATC Flow South) **.**

4. Flowgate 2006 (Eau Claire-Arpin 345kV) is inappropriately used in Example 1 of Appendix B. This example is dated and does not represent the MISO market start-up. The example must be changed or update to reflect existing practices.

5. The definition of Flowgate is taken from the NERC glossary. It differs from the Flowgate "term" used in the NERC Flowgate Administration Reference document (shown below)

(From document/glossary)

Flowgate A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

(From the Flowgate Administration reference document)

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

6. Duplicates of Footnotes. The numbers are poorly referenced.

In Appendix D [PJM/Midwest ISO, Inc. - Enhanced Congestion Management Method (Curtailment/Reload/Reallocation)] in NAESB Transmission Loading Relief Business Practices Draft - October 12, 2005 (http://www.naesb.org/pdf2/r04013a_rec_attachment.doc) the same footnote is listed under 1, 3, and 5. Number 3 and 5 footnotes should be eliminated as they are duplicates of footnote 1, listed below:

The RTO will conduct sensitivity studies to determine which external Flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the Balancing Authorities that exist today in the IDC). The RTO will perform the 4 studies as described in the MISO/PJM Paper "Managing Congestion to Address Seams" White Paper (Version 3.2, May 16, 2003, located on the NAESB website at http://www.naesb.org/pdf2/weq_bps101205w3.pdf) to determine which external Flowgates the RTO will monitor and help control. An external Flowgate selected by one of these studies will be considered a coordinated Flowgate (CF).

7. Reciprocal Flowgate Process versus Coordinated Flowgate Process.

ATC hasn't seen anywhere in Appendix D in NAESB Transmission Loading Relief Business Practices Draft - October 12, 2005 (http://www.naesb.org/pdf2/r04013a_rec_attachment.doc) language that describes distinction between Coordinated Flowgate and Reciprocal Flowgates. There should be language that describes how Coordinated Flowgates are utilized to establish reciprocal coordination agreements with neighboring entities (PJM and MISO). Coordinated flowgates are associated with a specific entity's operation sphere of influence. Reciprocal Coordinated Flowgates are associated with the implementation of a reciprocal coordination agreement between two entities. So reciprocal agreements go beyond the coordination processes described in the Appendix D.

8. Describe process of creating "Flowgates on the fly" or Dynamic Creation of Flowgates

Even though this doesn't necessarily falls into TLR Business Practice Draft (it is more appropriate to be included in Flowgate Administration Process document), it is important to be included in here. Who should create Flowgates on the Fly? What is the time involved in creating the temporary flowages and when the Operating Entity will incorporate the new flowgate into the monitoring process and when IDC will make possible calculation of market flows and NNL values.

DUKE ENERGY ("Duke") COMMENT
NAESB WEQ REQUEST for COMMENTS on RECOMMENDATION R04013A

"Version 0 Business Practice Standards – Development of post-split Version 0 Transmission Loading Relief (TLR) Business Practice Standard"

Duke commends the efforts of the Joint NERC / NAESB TLR Subcommittee on the division of the pre-split "Version 0" TLR standard into commercial and reliability standards and the WEQ Business Practice Subcommittee (BPS) on completing the post-split "Version 0" NAESB TLR Business Practice Standard. This TLR Business Practice Standard is to be considered for possible approval by the WEQ Executive Committee at the November 29, 2005 meeting.

Duke is most interested in keeping the NAESB and NERC standards development process coordinated, including the current effort on TLR commercial and reliability standards. NERC is in the process of gathering industry comments on this standard. In an effort to maintain effective coordination between these two standards (NAESB TLR Business Practice Standard and NERC TLR Reliability Practice Standard), Duke recommends that NAESB postpone approval action at its November 29, 2005 WEQ Executive Committee meeting until NERC is further along in its process.

Again, our ultimate goal is to ensure that the development activities between NAESB and NERC stay coordinated and complementary. It is not in the best interest of either organization or the industry for the two organizations to produce contradictory or overlapping standards through the lack of coordination. The Joint NERC / NAESB TLR Subcommittee produced their best effort, but since either organization could produce different results during their commenting periods, maintaining coordination is very important.

ENTERGY COMMENTS

NAESB WEQ REQUEST FOR COMMENTS ON RECOMMENDATION R04013a
Development of Post-split Version 0 Transmission Loading Relief (TLR) Business Practice Standard
Due November 18, 2005

Ed Davis
Entergy Services

NAESB has developed TLR business practices that are to be considered for approval by the Executive Committee at the November 29, 2005 WEQ EC meeting. Entergy recommends not approving the proposed TLR business practices, at this time, and that the industry continue to have one integrated TLR standard that encompasses both business practices and reliability standards overseen by both NAESB and NERC.

The following are Entergy's comments to the EC for their consideration. These comments fall into the following sections:

I. ONE TLR STANDARD
II. ARE THE TLR BUSINESS PRACTICES AND RELIABILITY REQUIREMENTS APPROPRIATELY DIVIDED?
III. NAESB/NERC COORDINATED IMPLEMENTATION PLANS LACKING
IV. NAESB/NERC FUTURE COORDINATION PLANS LACKING
V. NERC IDC REFERENCE DOCUMENT

I. ONE TLR STANDARD

Entergy believes that the interplay between the business practices and reliability practices associated with TLR is so intimate that they should not be separated. It would be best for the industry that one TLR standard be developed, modified, and presented to FERC jointly by NAESB and NERC.

Therefore, we recommend that the two aspects of TLR should not be divided into two standards practices as is contained in recommendation R04013a. We also recommend that the two standards setting organizations find a way to make the development and care of joint standards feasible.

II. ARE THE TLR BUSINESS PRACTICES AND RELIABILITY REQUIREMENTS APPROPRIATELY DIVIDED?

We do not know. It appears that IRO-006 has been divided into 3 major documents: these proposed NAESB TLR business practices, NERC draft TLR reliability standards, and the draft IDC Reference Documentation (included in the NERC TLR SAR). The answer to this question will require a detailed comparison of the final draft of all three documents with respect to IRO-006. The comparison can not be done at this time because NERC's TLR reliability standard and the IDC Reference Document are in the SAR drafting stage and are not near completion.

In addition, the IDC Reference Documentation appears to have significant business practice elements contained in it which should probably be in the NAESB business practice standard.

III. NAESB/NERC COORDINATED IMPLEMENTATION PLANS LACKING

The business and reliability participants of the electric industry had jointly developed the existing, integrated Transmission Loading Relief process which was subsequently adopted by FERC and included in all jurisdictional utility OATTs (FERC Order EL98-52, 85FERC62,353, December 16, 1998).

Given that the NAESB WEQ EC may file a portion of the TLR process with FERC, what does NAESB recommend FERC do with these new NAESB standards? Should FERC delete part of the existing, integrated TLR process and include these new standards? Which parts should FERC delete? Those parts to be deleted (or replaced) are not included in this recommendation.

How does NAESB, and NERC, recommend to FERC that the jurisdictional utilities modify their OATTs to incorporate these separate standards?

We recommend the industry present to FERC one integrated TLR process to replace the existing TLR process. FERC can then replace the existing TLR process with the new process. If that is not acceptable to the industry, then we recommend that the industry present to FERC one coordinated set of standards, having business practices and reliability standards, to be approved as a set and replace the existing FERC approved TLR process.

IV. NAESB/NERC FUTURE COORDINATION PLANS LACKING

While we do not agree with two sets of TLR standards, the industry may proceed down that path. If so, what process(es) do NAESB and NERC intend to follow to ensure the two sets of TLR processes remain coordinated in the future? Future coordination does not seem to have been addressed at this time, either for the near future nor the ongoing coordination.

There should be an item on the 2006 NAESB business plan that NAESB, and maybe NERC, may develop a "book" that would incorporate the NAESB business standards and

NERC reliability standards (when complete) for use by the industry. This seems somewhat awkward and may possibly lower reliability for the industry to split an integrated process, only to patch the two sets back together.

V. NERC IDC REFERENCE DOCUMENT

The IDC Reference Document that is included in the NERC TLR reliability standard appears to include significant business practices. For instance, the draft standard presented to NERC in the TLR SAR contains "Appendix B. IRO-006-0 Interchange Distribution Calculator (IDC) Reference Documentation" "Section B: Communication and Timing Requirements to Support Reallocation" contains the following:

> **3. Off-hour Transactions**. Interchange transactions with a start time other than *xx*:00 shall be considered for reallocation at *xx*+1:00. For example, an interchange transaction with a start time of 01:05 and whose tag was submitted at 00:15 will be considered for reallocation at 02:00.

This requirement appears to be a business practice, not a reliability standard, and is not contained in R04013a.

Has this IDC Reference Document been reviewed for business practices that should be in the NAESB standards?

Comments to NAESB WEQ BPS proposed post-split "Version 0"
NAESB Transmission Loading Relief (TLR) Business Practice Standard

Group Comments (Complete this page if comments are from a group.)

Group Name: FRCC Region
Lead Contact: Eric Senkowicz
Contact Organization: FRCC
Contact Telephone: 813-289-5644
Contact Email: esenkowicz@frcc.com

Additional Member Name	Additional Member Organization	NERC Region	NERC Segment
Pedro Modia	FRCC RC Agent / FPL	FRCC	1
Ed DeVarona	FRCC RC Agent / FPL	FRCC	1
Mark Bennett	Gainesville Regional Utilities	FRCC	5
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Eric Grant	Progress Energy - Florida	FRCC	1
Steve Wallace	Seminole Electric Cooperative	FRCC	4
Ted Hobson	JEA	FRCC	1
Ron Donahey	TECO	FRCC	1
Rusty S. Foster	City of Tallahassee	FRCC	3
Bob Remley	Clay Electric Cooperative	FRCC	3
Alan Gale	City of Tallahassee	FRCC	5

Comments:
The FRCC appreciates the significant effort put forth on the part of the WEQ Business Practices Subcommittee (BPS) and specifically the Transmission Loading Relief (TLR) Group in attempting to develop a complementary business practice to the existing NERC TLR Reliability standard. But at this time the FRCC cannot support ratification of "Version 0 Business Practice Standard - NAESB TLR Business Practice Standard in its proposed form.

The attempt at parsing out business practices and "splitting" the existing TLR procedure results in several regional concerns and serious reservations with respect to procedural clarity and maintaining the Reliability of the Bulk Electric System.

The major issues are as follows:
The TLR Business Practice contains Reliability Coordinator requirements and actions which are clearly associated with reliability of the Bulk Electric System (BES) and therefore inherently do not belong in a "Business" practice standard.

The resulting procedural split will require an industry-wide effort to modify training resources and protocols to address the documentation split (with very little benefit to improving BES reliability or addressing or improving any significant operating business issue).

The split introduces an additional level of ambiguity to an already complex procedure. The procedure has been developed around the unique IDC tool and to try to segregate the associated requirements into two documents is confusing and inappropriate for the end-users.

Process-wise the split also introduces synchronization issues with respect to requirements and coordination of a complex operating procedure between the NAESB Business Practice standard and the NERC Reliability standard as time goes on and the industry evolves.

Although the FRCC is a member organization of NAESB, we are concerned with the accessibility of NAESB standards by the whole of the Interconnections. As a result of the ratification of this Business Practice, Reliability Coordinators would be required to become members of NAESB in order to gain access to the copyrighted, actual business practices.

Finally, with the evolution of the ERO and the ensuing impacts on organizational structures and budgeting, the IDC tool funding mechanism is still being developed and a procedural split at this time could be premature since overall IDC functionality and requirements may be impacted in the near future.

In summary, we appreciate the opportunity to comment on this Business Practice, but based on the above, we would vote against adoption of the TLR Business Practice as written and would suggest that further development, if any on this standard should focus on a complementary document that describes the NERC TLR process for use by the "Business" community. Such a document should refrain from the imposition of any operating requirements on NERC (ERO) Reliability Coordinators, as those requirements should remain well within the realm of the NERC Reliability Standards process.

Individual Comment:
The following comment is offered on behalf of an end-user of the proposed documents:

"The IDC is the one interconnection wide tool for RC's to manage congestion and maintain reliability. It is a highly complex system with complicated links to our NERC ETAG scheduling system and drives all the communications required during curtailments. To split up its "Users manual" into reliability procedures and business practice considerations will affect its already compromised efficiency in obtaining required relief. The industry needs to concentrate on making curtailments and congestion management more straightforward".

ISO RTO Council
Standards Review Committee

Comments on NAESB Recommendation R04013A "Version 0 Business Practice Standards - Development of post-split Version 0 Transmission Loading Relief (TLR) Business Practice Standard"

The IRC supports the NAESB efforts to develop business practice standards to complement those NERC standards that have been rewritten in the "Version 0" effort to separate reliability requirements from business requirements. As IRC member companies are both market operators and reliability coordinators, we have a strong interest in seeing that business practices are effective and that reliability standards do not impede on commercial terms of transmission and market tariffs. IRC members have participated and commented throughout both NERC and NAESB standards drafting processes and have anxiously waited to see the final standards to determine whether all the current in effect TLR procedures have been adequately captured in the final NERC and NAESB standards.[1] We are encouraged to see that the joint effort between NERC and NAESB as recommended by the Joint Interface Committee has developed a final business practice standard that fulfills the scope of the original task.

The IRC does wish to express concerns about moving forward with 2 separate standards for a procedure that is so important for the effective management of congestion in many parts of the Eastern Interconnection. These concerns are not meant to be criticisms to NAESB or NERC standards processes as the IRC understands the charge given to both organizations through the authority of the NERC – NAESB-ISO/ RTO Council Memorandum of Understanding.

Our concerns are based on the fact that there will be 2 organizations, each with distinct processes and enforcement authorities, for highly interrelated sets of "steps" to accomplish a common goal. It is not the intent of our comments to argue for or against what elements of the TLR Business Practice are or are not for business purposes. Individual IRC members may file comments separately addressing these and other concerns. However, all members of the IRC are concerned that if both NERC and NAESB approve their respective TLR standards, the mere separation of the procedures themselves, regardless of which ones belong where, places challenges on the enforcement, implementation, and management of data systems of the TLR process and could jeopardize reliability and commercial outcomes.

Although the TLR process has always been recognized to carry both elements of reliability and commerce, NERC has in the past addressed commercial concerns through the then in existence Market Committee. NAESB can continue in this role where the Market Committee has left off and with greater authority. Since the primary purpose of the TLR standard is to alleviate congested or overscheduled paths, NERC has managed all aspects of that standard, from implementation, to enforcement, to data and communication requirements. Further, since the executors of the TLR standard are system operators, and not market operators, NERC provided a single source for efficient and effective management of the standard to ensure that system operators had clear authority and obligation to follow the entire TLR procedure.

With a new era of reliability standards emerging with the soon to be Electric Reliability Organization, the IRC believes that the purpose for the separation of the TLR standard between a reliability organization and a commercial organization has passed. Prior to the Energy Policy Act of 2005, FERC did not exercise authority over reliability matters. When NERC receives its ERO status, as we believe it will, all NERC standards will have the review and approval of FERC. The legislation is also clear that FERC will not defer any authority to NERC in areas that affect commerce. This ensures that commercial and market matters are adequately addressed in the reliability standards.

The IRC believes that because the TLR standard has such great implications to reliability, it is most effectively and efficiently managed under a single process and organization at NERC. We believe that NAESB can continue to provide value to the TLR standard through cooperative processes like the joint TLR subcommittee where reliability experts and market experts can work in conjunction to capitalize on the NERC- NAESB working relationship to address future changes and enhancements to the TLR standard and its supporting systems.

[1] While the California ISO and ERCOT ISO concur with these joint comments of the ISO/RTO Council, this concurrence should not be construed as agreement to utilize this standard.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

November 18, 2005

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

Dear Ms. McQuade:

Recommendation R04013A, "Version 0 Business Practices Standard Development of post-split Version 0 Transmission Loading Relief (TLR) Business Practice Standard"

I am writing to provide comments on behalf of the NERC Operating Committee's Operating Reliability Subcommittee on NAESB Recommendation R04013A, "Version 0 Business Practice Standard Development of post-split Version 0 Transmission Loading Relief (TLR) Business Practice Standard."

At its November 16–17, 2005 meeting, the Operating Reliability Subcommittee agreed to the following:

1. Based on industry comments, as well as its own deliberations, to withdraw its standards authorization request that would remove the business practices from NERC standard IRO-006-0, "Transmission Loading Relief," and

2. To request that the North American Energy Standards Board discontinue developing the complementary business practice standards as described in its Recommendation R04013A, and

3. To request that the NAESB Business Practices Subcommittee work with the Operating Reliability Subcommittee on an on-going basis on all future changes to the TLR Procedure.

History — In August 2004, NERC and NAESB agreed to begin a joint effort to update the Eastern Interconnection TLR Procedure, as reflected in Attachment 1 to reliability standard IRO-006-0, to divide the reliability requirements and business practices, and to incorporate other necessary improvements to the TLR Procedure. In December 2004, NERC and NAESB formed the joint TLR Subcommittee to separate the TLR requirements that are necessary for reliability, as distinguished from those TLR requirements that are business practices, and provide recommendations to the NERC Operating Reliability Subcommittee and NAESB Business Practices Subcommittee.

As a result of the TLR Subcommittee's agreements on July 14, 2005, the Operating Reliability Subcommittee submitted a standards authorization request to remove the business practices from NERC

standard IRO-006, "Transmission Loading Relief." NERC posted the SAR on August 3, 2005, with comments due on September 2, 2005.

Industry Comments — Of the twelve sets of industry comments that NERC received, six did not believe there was a reliability need for the proposed standard. Many of the comments cited the intimate connection between the curtailment process itself and the business practice rules that govern the curtailment order within that process. While splitting the reliability and business practices is possible, many do not believe it is worth the risks of confusing the system operators, who would need to consult separate standards as they work their way through the various TLR curtailment levels. Based on these comments, the Operating Reliability Subcommittee does not believe sufficient industry support exists to pursue separating the business practices from this reliability standard.

Subcommittee Deliberations — In addition to the industry comments, the subcommittee's own discussions pointed out the complexities of keeping the Interchange Distribution Calculator (IDC) algorithms aligned with the curtailment order business practices and the FERC *pro forma* tariff. This is the responsibility of the NERC Interchange Distribution Calculator Working Group, Distribution Factors Working Group, and the IDC services vendor. The Operating Reliability Subcommittee relies on the expertise of all these groups when contemplating new algorithms, for either reliability or marketplace enhancements, to the TLR Procedure.

*** * ***

With these considerations in mind, the Operating Reliability Subcommittee decided to withdraw the IRO-006 standards authorization request and, therefore, requests that NAESB discontinue its work on complementary business practice R04013A.

The subcommittee is keenly aware that changes to the TLR procedure must have marketplace consideration and input. Therefore, the subcommittee supports the involvement of NAESB and its Business Practices Subcommittee on all future TLR procedure changes and enhancements. The NERC and NAESB staffs will ensure that the Business Practices Subcommittee, and other NAESB groups whose scope includes aspects of the TLR procedure, are invited to attend all ORS meetings, and that we provide sufficient time for discussion and standards drafting.

The Operating Reliability Subcommittee believes these recommendations will continue to provide the excellent reliability standards and complementary business practices that we need for the TLR procedure to work effectively.

Sincerely,

Kim Warren

Kim Warren
Vice Chairman
Operating Reliability Subcommittee

DMB:sbc

Attachment (Operating Reliability Subcommittee Roster)

Operating Reliability Subcommittee

Chairman	James D. Castle Manager of Customer Relations	New York Independent System Operator 3890 Carman Road Schenectady, New York 12303	(518) 356-6244 (518) 356-6118 Fx jcastle@ nyiso.com
Vice Chairman	Kim Warren Manager Regulatory Affairs	Independent Electricity System Operator 655 Bay Street Suite 410 PO Box 1 Toronto, Ontario M5G 2K4	(416) 506-2821 Fx kim.warren@ ieso.ca
Executive Committee	Garth Arnott Director of Energy Operations	North Carolina Electric Membership Corp. P.O. Box 27306 Raleigh, North Carolina 27611	(919) 875-3025 (919) 954-1080 Fx garth.arnott@ ncemcs.com
Executive Committee	D. Jack Bernhardsen President/Manager	Pacific Northwest Security Coordinator, Inc. 5411 N.E. Highway 99 TO-DITT1-NWSC Vancouver, Washington 98663	(360) 418-2956 (360) 993-2204 Fx jack@ pnsc-center.com
	Daniel R. Boezio Director, Transmission Reliability	American Electric Power 4th Floor P.O. Box 16631 Columbus, Ohio 43216-6631	(614) 716-6630 (614) 716-6661 Fx drboezio@aep.com
	Roger C. Harszy Director of Area Operations	Midwest ISO, Inc. 701 City Center Drive Carmel, Indiana 46032	(317) 249-5400 (317) 249-5910 Fx rharszy@ midwestiso.org
	Anthony Jankowski	W237 N1500 Busse Road Waukesha, Wisconsin 53188-1124	(262) 544-7117 (262) 544-7099 Fx tony.jankowski@ we-energies.com
	Frank J. Koza General Manager, Regional Operations	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 666-4228 (610) 666-4282 Fx kozaf@pjm.com
	Pedro Modia Director, Power Supply	Florida Power & Light Co. 4200 West Flagler Street Room 3400 Miami, Florida 33134	(305) 442-5246 (305) 442-5022 Fx pedro_modia@ fpl.com
	H. Steven Myers Manager of Operations Support	Electric Reliability Council of Texas, Inc. 2705 West Lake Drive Taylor, Texas 76574-2136	(512) 248-3077 (512) 248-3055 Fx smyers@ercot.com
	Lanny D. Nickell Manager, Coordinated Operations	Southwest Power Pool 415 North McKinley Suite 140 Little Rock, Arkansas 72205-3020	(501) 614-3232 (504) 664-9553 Fx lnickell@spp.org

	Robert D. Priest Assistant General Manager	Clarksdale Public Utilities Commission P.O. Box 70 Clarksdale, Mississippi 38614	(662) 627-8402 (662) 627-8403 Fx priest@ cableone.net
	J. Clifford Shepard Project Manager, Generation	Southern Company Generation 600 North 18th Street BS-8261 Birmingham, Alabama 35202	(205) 257-6116 (205) 257-5792 Fx jcshepar@ southernco.com
	Gregory P. Stone Manager, Grid Operations Engineering	Duke Energy EC02B 526 S. Church Street Charlotte, North Carolina 28202	(704) 382-8021 (704) 382-6938 Fx gpstone@ duke-energy.com
Staff Coordinator	Larry J. Kezele Manager-Operations Reliability and Market Services	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5731	(609) 452-8060 (609) 452-9550 Fx larry.kezele@ nerc.net

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If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Manager of Standards, Mark Ladrow at 609-452-8060 or at mark.ladrow@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

1. Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.

Commenter	Yes	No	Comment	Response
TOTAL:	**6**	**6**		
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo	X		N/A	
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes	X			
ISO NE Cheryl Mendrala		X	This proposed standard change was not initiated due to reliability needs	
Entergy Services, Transmission Ed Davis Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban		X	The interplay between the business practices and reliability practices associated with TLR is so intimate that the two should not be divided into two standards practices. It would be best for the industry that one TLR standard be developed by the two organizations.	
Joint Interchange Scheduling Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski	X			

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

Taryn McPherson Salah Kitali Joel Mickey Andrew Burke				
AEP Raj Rana		X	We support the NERC/NAESB initiative to split the TLR document in order extract the business practice aspects. However, there is no reliability need for this proposed standard change. The reliability need in terms by managing power flow relief in a pre-defined time period in order to maintain security of the system did not change. However, this draft does not provide reliability performance specifications, such as X MW or % of relief in Y minutes. The NERC portion of this standard should specify what is needed to maintain the system security in the interconnected environment, while the NAESB portion should specify the road map as to how to do it.	
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members		X	The MRO does not believe there is a reliability need for the proposed standard change. We would contend that the change provides confusion to a very important reliability process. In order to understand the process the standard and the business practice are necessary.	
Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell Elizabeth B. Fleming G. O'Neal Hamilton Mignon L. Clyburn C. Robert Moseley	X			
Ohio Valley Electric Corp. Scott R. Cunningham	X			
IESO, Ontario Dan Rochester		X	We do not feel there is a reliability need for the proposed standard "change". We would contend that the change provides confusion to a very important reliability process. In order to understand the process the standard and the business practice are necessary.	
Southern Company Generation Roman Carter Joel Dison	X			

Clifford Shepard Lucius Burris Steve Lowe				
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha		X	This proposed standard change was not initiated due to reliability needs. NPCC Participating members believe that the change is in conflict to very important reliability rules. In order to understand the process the standard and the business practice are necessary.	

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2. Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.

Commenter	Yes	No	Comment	Response
TOTAL:	**5**	**7**		
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo	X		N/A	
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes		X	We feel that the division between business practices and reliability standards may not have gone far enough. The reliability standards should focus on establishing the criteria for initiation of different TLR levels and the required timeframes for relief. Business practices should focus on how the curtailments are executed to achieve the relief levels in the timeframes required by the reliability standard.	
ISO NE Cheryl Mendrala		X	- Section 2.6 and 2.7 in the original standard defined step-by-step actions the Operator is to take under TLR Levels 5a and 5b. These actions have been removed and currently reside in the proposed NAESB standard. It is not appropriate for a business practice standard to define actions to be taken by a Reliability Coordinator in real-time operations to resolve a reliability issue. The need for a TLR is in response to a problem with reliability on the system. There is no doubt that the Operator must be presented with all the information that is contained in both the proposed NERC and NAESB standards in order to issue that TLR. If the operator does not know what transactions are available in any given category, they do not know what TLR level is needed to resolve the situation. Therefore, we cannot agree with the assertion that the information contained in the NAESB standard does not impact reliability. We agree that some aspects of the original IRO-006 are 'business practices,' and agree that the completed effort generally meets the original intent of splitting the business practice and reliability components. However, seeing the resulting split, it is clear that these business practices have a direct impact on reliability and we believe they should be maintained within one single standard to prevent confusion and conflicts. Also, since the fundamental practice for defining the priorities and treatment of transactions under each TLR level is consistent with the FERC pro-forma tariff, there is minimal subjectivity involved in the business practices that are included in the original NERC standard.	
Entergy Services, Transmission Ed Davis		X	A complete response to this question is inappropriate at this time.	

Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban			It appears that IRO-006 will be divided into 3 major documents: NERC TLR reliability standards, NAESB business practices, and the IDC Reference Documentation. The answer to this question will require a detailed comparison of all three documents with respect to the existing IRO-006. We do not have the NAESB document in front of us in order to make that detailed comparison. In addition, it does not appear that a detailed comparison of the three documents has been requested since the SAR request states in the last paragraph that the development effort will begin by assessing for completeness and accuracy the revised Attachment 1.	
Joint Interchange Scheduling Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski Taryn McPherson Salah Kitali Joel Mickey Andrew Burke	X			
AEP Raj Rana		X	The two documents are overlapping. Same statements in both documents.	
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members		X	Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2, 3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of 1.6.6 was added to the Standard in June of this year with 100% of the ballot body approval, it should remain as part of this standard.	
Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell	X			

Elizabeth B. Fleming G. O'Neal Hamilton Mignon L. Clyburn C. Robert Moseley				
Ohio Valley Electric Corp. Scott R. Cunningham	X			
IESO, Ontario Dan Rochester		X	The reliability and business practices within the TLR process are integrated to such an extent that the details need to remain contained within a single document for clarity. Concerns regarding the ability to effectively manage the model and the process with the current proposed split need to be addressed. The ability to follow developing market issues must also be retained. Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2, 3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of 1.6.6 was added to the Standard in June of this year with approval of 100% of the ballot body. It should remain as part of this standard.	
Southern Company Generation Roman Carter Joel Dison Clifford Shepard Lucius Burris Steve Lowe	X			
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha		X	- Section 2.6 and 2.7 in the original standard defined step-by-step actions the Operator is to take under TLR Levels 5a and 5b. These actions have been removed and currently reside in the proposed NAESB standard. It is not appropriate for a business practice standard to define actions to be taken by a Reliability Coordinator in real-time operations to resolve a reliability issue. The need for a TLR is in response to a problem with reliability on the system. The Operator must be presented with all the information that is contained in both the proposed NERC and NAESB standards in order to issue that TLR. If the operator does not know what transactions are available in any given category, they do not know what TLR level is needed to resolve the situation. NPCC participating members do not agree with the assertion that the information contained in the NAESB standard does not impact reliability. Some aspects of the original IRO-006 are 'business practices,' and that the completed effort generally meets the original intent of splitting the business practice and reliability components. However, seeing the resulting split, it is clear that these business practices have a direct impact on reliability and they should be maintained within one single standard to prevent confusion and conflicts. Also, since the fundamental practice for defining the priorities and treatment of transactions under each TLR level is consistent with the FERC pro-forma tariff, there is minimal subjectivity involved in the business practices that are included in	

			the original NERC standard. Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2, 3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of 1.6.6 was added to the Standard in June of this year with 100% of the ballot body approval, it should remain as part of this standard.	

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3. Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.

Commenter	Yes	No	Comment	Response
TOTAL:	**4**	**8**		
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo		X	N/A	
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes	X		Everything in the proposed Attachment 1 - IRO-006-0 from Section 3 to the end of Attachment 1, including Appendices A and B, should be removed from the reliability standard and incorporated into the TLR Business Practices document. This material gets into the internal workings of the tool itself rather than dealing with the overall guiding principle of providing, and maintaining, relief within a specific timeframe.	
ISO NE Cheryl Mendrala		X	See response to question 2.	
Entergy Services, Transmission Ed Davis Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban	X		The NERC TLR reliability standard part of this documentation appears to be all reliability related. However, the IDC Reference Document appears to have significant business practice elements contained in it.	
Joint Interchange Scheduling Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski Taryn McPherson Salah Kitali Joel Mickey Andrew Burke		X		
AEP Raj Rana	X		We believe that items like firm/non-firm transactions types, TLR levels etc. should be taken out of the reliability portion of this	

			standard. These items should be included in the NAESB portion. The reliability portion should only address the needed relief amount on constrained facilities and the time under which the relief should be provided in order to maintain security of the interconnected network.	
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members		X		
Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell Elizabeth B. Fleming G. O'Neal Hamilton Mignon L. Clyburn C. Robert Moseley		X		
Ohio Valley Electric Corp. Scott R. Cunningham	X		At times, RTO ramp limitations are invoked when TLR curtailments occur. This issue is not covered in the standard, but seems to be related to a business practice, rather than a reliability issue. Perhaps the ramp limitation should be waived or adjusted if the limitation is caused by the curtailments that occur with the TLR.	
IESO, Ontario Dan Rochester		X		
Southern Company Generation Roman Carter Joel Dison Clifford Shepard Lucius Burris Steve Lowe		X		
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha		X	See response to question 2.	

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4. Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.

Commenter	Yes	No	Comment	Response
TOTAL:	**4**	**7**		
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo		X	N/A	
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes	X		Sections 3.2.1, 3.2.1.1 and 3.2.1.2 should be moved to the reliability standard since they deal more with how and why a Level 2 TLR is initiated than with the internal workings of the IDC.	
ISO NE Cheryl Mendrala	X		See response to question 2.	
Entergy Services, Transmission Ed Davis Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban		X	We can not answer this question since we do not have the NAESB proposal TLR business practices in this package.	
Joint Interchange Scheduling Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski Taryn McPherson Salah Kitali Joel Mickey Andrew Burke		X		
AEP Raj Rana			No comments. The TLR business practices document is not available.	

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Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members	X		See comments in question 2.	
Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell Elizabeth B. Fleming G. O'Neal Hamilton Mignon L. Clyburn C. Robert Moseley		X		
Ohio Valley Electric Corp. Scott R. Cunningham		X		
IESO, Ontario Dan Rochester		X	See comments in question 2.	
Southern Company Generation Roman Carter Joel Dison Clifford Shepard Lucius Burris Steve Lowe		X		
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha	X		See response to question 2.	

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5. Do you have any other comments on these proposed changes?

Commenter	Yes	No	Comment	Response
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo	X		My only concern with the splitting of reliability requirements and business practices is how they will be managed and/or coordinated in the future. I'm not sure what value is added to the reliability of the grid by now having our grid operators manage their respective systems with a NERC manual in one hand and a NAESB manual in the other. Right now the two documents are in synch with one another; however, as we move forward in time, what will be the process for conflict resolution between the two?	
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes	X		Section 1.5.1 of Attachment 1 refers to treatment of Interchange Transactions not in the IDC in accordance with NAESB business practices, but we could not find any reference to this treatment in the TLR business practices.	
ISO NE Cheryl Mendrala	X		Recommend restoring the reference to RCIS tool in 1.4. That reference was eliminated when the old 1.4.1 was removed. - The old 1.5.1 was removed. There's a general statement added to 1.2 that says "In addition, a Reliability Coordinator may implement other NERC-approved procedures to request relief to mitigate any other transmission constraints as necessary to preserve the reliability of the system." But, that phrase does not seem to capture the same intent as the previous 1.5.1 wording. - Section 1.5.3 the numbering on this section is very confusing. Suggest the following: 1.5.3.1. Causes of questionable IDC results may include: (1) Missing Interchange transactions that are known to contribute to the Constraint, (2) Significant change in transmission system topology, or (3) TDF matrix error. 1.5.3.2 Impacts of questionable IDC results may include: (1) relief that would have no effect on, or aggravate the constraint or (2) that would initiate a constraint elsewhere. 1.5.3.3. If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the relief request list are made. - Title of Section 2 should be changed to be only "Transmission Loading Relief (TLR) Levels." - Section 3 is missing section 3.1. - Suggest that Section 3.2 include a reference to the fact that transactions submitted after the XX:25 deadline will put on HOLD.	

			- Are Section 3.3.3 and Section 3.4.3 referring back to the deadline defined in 3.2? If so, that section should be referenced. - Text in 3.3.1.1 and 3.3.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.3.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour". - Text in 3.4.1.1 and 3.4.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.4.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour". - The section notation of Appendix B should be modified. The Section numbering shown in the index is not how the headings are titled in the Sections. Also, Section F and Section G should not be 5.1 and 5.2; they should be at the highest index level. General Comment: There have been changes to the congestion management process over the last few years that involve the use of Market information by the IDC. Any new standards addressing the TLR process and the IDC, whether in NERC or NAESB, should consider addressing the current information available to the IDC and include some mention of that information in that standard development. General Comment: One other practical concern that has not been addressed is the ownership, impact and funding of the IDC tool that automates the 'business practices' of implementing a TLR for the Operator. The split of the original NERC IRO-006 should not be adopted until this issue is addressed and resolved.	
Entergy Services, Transmission Ed Davis Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban	X		The SAR contains the statement that the urgent action revision to Attachment 1 addressing dynamic schedules will be incorporated into the NAESB business practices. We suggest starting with IRO-006-1, rather than with IRO-006-0. Please delete all references to IRO-006-0 (and IRO-006-1) in headers, footers, titles, etc. This new document will result in a new version of IRO--006. This current draft is not version 0 or 1. Please delete all references to adoption by the NERC Board of Trustees, Effective Date, and all dates because the document we are viewing has not been adopted by the BOT and does not have an Effective Date. Please provide a redline version showing the draft changes to IRO-006-1. This redline would make review and comment much easier for commenters. We appreciate the development of the matrix and would probably find it useful for keeping track of the disposition of each requirement in the original IRO-006. However, in its current form we do not understand which columns relate to which documents and the row designations are not clearly understood.	
Joint Interchange Scheduling	X		1. We request that the scope of this SAR be expanded to	

Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski Taryn McPherson Salah Kitali Joel Mickey Andrew Burke			include resolving the reloading of curtailed transactions above their reliability limit by an entity other than the initiating entity or above any pre-existing reliability or market profiles. 2. We also request that the scope of the SAR be expanded to include standards for when curtailments may be denied and when curtailments may be issued. 1 - There have been several instances where a curtailment has been issued and then been automatically or manually reloaded above the reliability limit. The automatic reload problem created by the IDC has been resolved by CO-148, automatic reload by other back office applications has not been corrected, nor have manual adjustments. There are several options available for correcting this problem. This should be addressed by specifying requirements and performance measures in the TLR standard and may also be addressed through NAESB business practices and modifications to the e-Tag specification. Also, any pre-existing curtailment levels are lost. JISWG recommends that the entity who has issued the curtailment be the only entity able to authorize the reload. When the reload occurs the energy profile should be limited to the next lowest reliability limit or market adjustment profile. 2- Under normal circumstances, a curtailment (issued for reliability reasons) should not be denied. However, there are some limited circumstances where a curtailment should be denied. For example, if a curtailment comes in and the generator cannot meet the ramp requirements, then the curtailment could be denied and would be reissued for the next scheduling interval. This ensures that the tags reflect actual conditions. In other cases, curtailments are sometimes issued when PSE's cannot make their market level adjustments prior to cutoff. The TLR standard should address those specific reasons for denying a curtailment. Reliability is compromised when curtailments are denied for non-reliability reasons. Reliability may also be compromised when curtailments are issued for non-reliability reasons. If scope of the SAR is adjusted, JISWG volunteers to assist the drafting team with providing specific language for the TLR standard addressing these issues.	
AEP Raj Rana	X		Use of proxy flowgates by the reliability coordinators must be prohibited. This practice must be explicitly addressed in this standard because, the use of proxy flowgates not only will result in mis-allocation of corrective actions, but at worst could even result in actions being taken that actually increase flows on the limiting element, instead of decreasing them.	
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell	X		It was very difficult to review the changes to the standard without a redline copy. In order to perform our review we made a redline of the original standard. The MRO does not support this modification. The proposed change provides confusion to a very important reliability process. Also the proposed standard references a NAESB standard which is inconsistent with the	

Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members			NERC Standards Process Manual which says "All mandatory requirements of a reliability standard shall be within an element of the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There are mandatory parts of the proposed standard in the NAESB business practice and are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in synchronization when changes are made.	
Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell Elizabeth B. Fleming G. O'Neal Hamilton Mignon L. Clyburn C. Robert Moseley		X		
Ohio Valley Electric Corp. Scott R. Cunningham	X		The use of proxy flowgates is not mentioned at all in the proposed standard. The use of proxy flowgates should not be allowed, except in very unusual circumstances. If use of a proxy flowgate is necessary, such use should be justified and approval from all affected parties should be obtained.	
IESO, Ontario Dan Rochester	X		The IESO does not fully support the modifications proposed in this SAR. The proposed change provides confusion to a very important reliability process. Also the proposed standard references a NAESB standard which is inconsistent with the NERC Standards Process Manual which says "All mandatory requirements of a reliability standard shall be within an element of the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There are mandatory parts of the proposed standard in the NAESB business practice that are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in synchronization when changes are made. As acknowledged by the TLR Subcommittee that worked to create this proposed split, the business practices and reliability aspects of TLR are very intertwined. In effect, the information in both the proposed NERC and NAESB standard must be simultaneously available to the Operators in the Control Room, in order for them to operate the system reliably. While the effort to create this initial split in the TLR standards has been completed, consideration should be given as to how this split will	

			be maintained, if going forward, before it is adopted by the industry. Operator training issues, as well as the ownership and funding of the IDC tool should be considered in this evaluation before such a significant step is taken on a standard that is fundamental to the reliability of the Eastern Interconnection. This is an important process that requires a complete understanding of the impact of separating the business practice from the reliability concepts. It is not clear that the current proposed document split will retain the integrity of the TLR process. The potential negative impact of degrading the RC's ability to manage loop flow dictates that any change in documentation and responsibility must proceed carefully.	
Southern Company Generation Roman Carter Joel Dison Clifford Shepard Lucius Burris Steve Lowe	X		As NAESB and NERC standards are approved and implemented which require close coordination between the two organizations, the need for a common "Operations Manual" may become necessary for System Operators.	
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha	X		This is an important process that requires a complete understanding of the impact of separating the business practice from the reliability concepts. It is not clear that the current proposed document split will retain the integrity of the TLR process. The potential negative impact of degrading the RC's ability to manage loop flow dictates that any change in documentation and responsibility must proceed carefully. NPCC participating Members believe the proposed change provides confusion to a very important reliability process. There are mandatory parts of the proposed standard in the NAESB business practice that are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in synchronization when changes are made. Recommend restoring the reference to RCIS tool in 1.4. That reference was eliminated when the old 1.4.1 was removed. - The old 1.5.1 was removed. There's a general statement added to 1.2 that says "In addition, a Reliability Coordinator may implement other NERC-approved procedures to request relief to mitigate any other transmission constraints as necessary to preserve the reliability of the system." But, that phrase does not seem to capture the same intent as the previous 1.5.1 wording. - Section 1.5.3 the numbering on this section is very confusing. Suggest the following: 1.5.3.1. Causes of questionable IDC results may include: (1) Missing Interchange transactions that are known to contribute to the Constraint, (2) Significant change in transmission system topology, or (3) TDF matrix error. 1.5.3.2 Impacts of questionable IDC results may include: (1)	

			relief that would have no effect on, or aggravate the constraint or (2) that would initiate a constraint elsewhere. 1.5.3.3. If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the relief request list are made. - Title of Section 2 should be changed to be only "Transmission Loading Relief (TLR) Levels." - Section 3 is missing section 3.1. - Suggest that Section 3.2 include a reference to the fact that transactions submitted after the XX:25 deadline will put on HOLD. - Are Section 3.3.3 and Section 3.4.3 referring back to the deadline defined in 3.2? If so, that section should be referenced. - Text in 3.3.1.1 and 3.3.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.3.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour". - Text in 3.4.1.1 and 3.4.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.4.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour". - The section notation of Appendix B should be modified. The Section numbering shown in the index is not how the headings are titled in the Sections. Also, Section F and Section G should not be 5.1 and 5.2; they should be at the highest index level. General Comment: There have been changes to the congestion management process over the last few years that involve the use of Market information by the IDC. Any new standards addressing the TLR process and the IDC, whether in NERC or NAESB, should consider addressing the current information available to the IDC and include some mention of that information in that standard development. In addition, Operator training issues, as well as the ownership and funding of the IDC tool should be considered in this evaluation before such a significant step is taken on a standard that is fundamental to the reliability of the Eastern Interconnection. General Comment: One other practical concern that has not been addressed is the ownership, impact and funding of the IDC tool that automates the 'business practices' of implementing a TLR for the Operator. The split of the original NERC IRO-006 should not be adopted until this issue is addressed and resolved.	

Southern Company Generation
NAESB TLR Business Practice Standard
Comments on R04013A

When the NAESB "Version 0" Business Practice Standard was adopted in 2004, the Standard represented a duplication of the NERC TLR Standard, IRO-006. The determination was made by both NERC and NAESB that the commercial and reliability aspects of the TLR procedures would be split immediately following the adoption of the "Version 0" standards.

Recommendation R04013A represents the business practice sections resulting from the Joint NERC/NAESB TLR Subcommittee efforts that divided the commercial and reliability standards. Southern Company Generation has participated actively in this effort and is pleased to be commenting on both organizations' request for comments.

We commend the joint effort between NERC and NAESB as recommended by the Joint Interface Committee and believe standard R04013A fulfills the original scope provided to the NERC/NAESB TLR subcommittee. Southern Company Generation wishes to express its support for moving forward with separate NAESB and NERC standards for TLR procedures recognizing that it is important for both the market and reliability entities. Once NERC and NAESB approve their respective TLR standards, the two organizations should file their respective standard simultaneously with the FERC.

NERC previously addressed commercial concerns through the now dissolved Market Committee. NAESB now fulfills this role for the Market Committee and addresses issues related to the commercial aspects of the electric power system. The primary purpose of the TLR standard is to alleviate transmission congestion utilizing the commercial and reliability standard requirements established by the respective NERC and NAESB standards. The TLR standards will continue to be implemented by the System Operators and Reliability Coordinators just as they were implemented under NERC's Policy 9. To assist each of these entities with implementation, NERC and NAESB have an agreement to develop an Operating Training Manual which will contain all requirements from both the NERC and NAESB standards related to the TLR procedures. As needed, future revisions to these TLR standards should continue to be addressed by the NERC/NAESB TLR subcommittee with input from participants from each organization.

With the recent passing of the Energy Policy Act (EPAct) of 2005, the FERC will not only have authority over the wholesale market but also with reliability through the soon-to-be Electric Reliability Organization (ERO), thus providing a unified direction for both NERC and NAESB. The EPAct also makes it clear that FERC will not defer any authority to NERC in areas that affect commerce, further emphasizing that the NAESB commercial business practices will remain separate from NERC reliability standards.

I believe it is very important that NERC and NAESB continue their excellent relationship and cooperation with the development of standards as it has done with the NERC/NAESB TLR subcommittee and complement each organization in that respect.

Southern Company - Transmission
Comments on "Version 0 Business Practices Standard Development of post-split Version 0 Transmission Loading Relief (TLR) Business Practice Standard" – R04013A
Submitted By: Jim Busbin / Southern Company – Transmission

Southern Company Transmission has no concerns with either the original work of the Joint NERC/NAESB TLR Task Force or the subsequent work of the NAESB Business Practices Subcommittee. We feel that a fair representation of business practice standards has been produced in the NAESB document as derived from the original NERC IRO-006 policy document.

Our concerns lie with the bigger picture – the need to physically separate the original IRO-006 in the first place. We see several areas in which there appear to issues with no substantive answers, at least at this point. They include:

Effect on Real Time Grid Operators:
As we have stated in prior comments, we are not sure what value is added to the reliability of the grid by now having our grid operators manage their respective systems with a NERC manual in one hand and a NAESB manual in the other. A compromise presently being discussed is the introduction of yet a third manual, a compilation of the two "split" manuals. We feel the introduction of needless operational complexities is not prudent with respect to the maintenance of grid reliability.

Coordination between NERC and NAESB Manuals:
As presently separated, the NERC Reliability Standards and NAESB Business Practice Standards are in synchronism – each complements the other with no apparent conflict. However, as we move forward in time, there appears to be no provision for conflict resolution between the two, no guarantee that synchronism will be maintained in the future.

Southern Company Transmission is not in favor of splitting the document until issues such as these and those that would possibly fall into a Version 0+ category; for example, NAESB standards compliance, have been adequately addressed.

We commend the members of the joint NERC/NAESB TLR Task Force and NAESB Business Practices Subcommittee on their excellent work in identifying and setting aside business practices within the original NERC policy document. We thank you for the opportunity to provide comment on this important industry issue.

Tennessee Valley Authority (TVA)

Comments on NAESB Recommendation R04013A – Version 0 Business Practice Standards – TLR Post-Split Business Practice Standard

TVA participated and supported the efforts to split the commercial and reliability aspects of the NERC TLR standard from both the NERC and NAESB perspectives in an effort to comply with the joint decisions set forth during the original Version 0 activities. While the division of the TLR standard is somewhat cumbersome and may be perceived as confusing to administer, it is doable as long as we move forward with a well-thought out plan to ensure the appropriate education and understanding of our grid operators. We believe this will be the key to administering any of the current Version 0 business practices (post-split) that are part of FERC's NOPR in Document RM05-5-000 and will be true for any issues that NAESB and NERC work on collaboratively in the future. We are committed to doing what is "appropriate" for the overall electric industry to ensure we continue with a safe and reliable operation.

After a review of the NAESB TLR Business Practice in comparison to NERC's IRO-006-1, we have the following minor issues that we would like to see resolved before moving forward.

Item 1 – Definitions Section:
Adding approved language on how to handle Dynamic Schedules calls for the addition of not only the definition of a Dynamic Schedule but also the addition of several definitions (acronyms) that are listed within those definitions, including:

Dynamic Schedule – A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.

Area Control Error (ACE) – The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

Automatic Generation Control (AGC) – Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Frequency Bias – A value, usually expressed in megawatts per 0.1 hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection and frequency error.

**definitions taken from NERC Glossary*

In the definition of Constrained Facility, spell out SOL and IROL instead of using the acronyms.

Item 2 – Capitalizations

Please capitalize the word "Appendix" anywhere a specific appendix is referenced in the document.

Please check the document to make sure Contract Path is capitalized when used as a defined term.

Item 3 – Use of Terms

Please check the document to ensure references listed as Generation and Load Control Areas are changed to Balancing Areas to match Functional Model language.

Please check references to NERC TLR site and change to NERC TLR website to match IRO-006-1.

Item 4 – Language Matches

Please compare NAESB Section 3.8 to the language found in IRO-006-1 section 2.8.2 to see if wording on "safe and stable condition" needs to read "secure state."

Please compare NAESB Section 3.9 to the language found in IRO-006-1 section 2.9.1 to see if wording on "returned system to TLR level 0" needs to read "reliable state."

Item 5 - Appendices

Appendix C: second table needs a title…consider the title…Applied Transaction Curtailment Formulas." In addition, the first table has capitalized terms like Weighting Factor. Those terms are not in the Definitions section for the business practice, so do we need to add or can they stand alone in the Appendix.

Appendix D: line 863 – There is a reference to Priorities 1-6. Does this need a reference back to the Business Practice Section 2.1 which defines those priorities? Line 883 – Does this title need to be capitalized in its entirety? Line 897 – There's a reference to market flow calculation methodology. Do we need to reference the PJM White Paper which outlines this methodology?

NORTH AMERICAN ENERGY STANDARDS BOARD

Executive Committee Meeting – WEQ, REQ, RGQ, WGQ Meeting Materials

Wholesale Electric Quadrant

TAB 12

Recommendations for Vote – R04035/R05002: Clarify OASIS 1A Nomenclature and Amend WEQ Standard 4.19/ Amend sections 9.5 and 10.5 of the OASIS 1A Redirect Standards

- Recommendation R04035/R05002 is attached. The comment period for this request will end on November 28. One set of comments was received to date. As others are received they will be provided under separate cover.
- To approve the recommendation that would clarify OASIS 1A nomenclature, amend WEQ Standard 4.19, and amend sections 9.5 and 10.5 of the OASIS 1A redirect standards, a motion to accept the recommendation would be made by a WEQ EC member, and the resulting vote would need to be 67% of the WEQ EC members (20 of 29 members) and 40% of each segment's EC members.
- The materials in Tab 12 correspond to agenda item 5 for the WEQ EC agenda.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE

For Quadrant:	**Wholesale Electric Quadrant**
Requesters:	**ESS/ITS**
Request Number:	**R04035 & R05002**
Request Title:	**Request to Modify Standards & Revision of Redirect Standards 9 and 10**

1. RECOMMENDED ACTION:

___ Accept as requested
_X_ 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:**
___ Initiation	___ Initiation
_X_ Modification	_X_ Modification
___ Interpretation	___ Interpretation
___ Withdrawal	___ Withdrawal
___ Principle	___ Principle
_X_ Definition	_X_ 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

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE

For Quadrant:	**Wholesale Electric Quadrant**
Requesters:	**ESS/ITS**
Request Number:	**R04035 & R05002**
Request Title:	**Request to Modify Standards & Revision of Redirect Standards 9 and 10**

3. RECOMMENDATION

SUMMARY:

This recommendation addresses requests R04035 and R05002. R04035 is a request to address comments received by the WEQ ESS/ITS on the draft of its recommendation for requests R04005-A (OASIS Baseline Business Practices – Standards 1 -7), R04006-B (Multiple Requests – Standard 8) and R04006-C (Redirects – Standards 9 and 10). As the comments recommended substantive changes to the standards, it was not appropriate to address these comments as a part of the initial issuance of the standards. Now that the standards have been ratified, the ESS/ITS combined the comments into Request R04035 being addressed herein.

This recommendation also addresses the following clarification issues brought up in R04035 and R05002:

- Standard 4.19 needs to be clarified to reflect the Transmission Provider is not required to COUNTEROFFER a confirmed reservation.
- Clarification that the numbered components are “requirements” of the OASIS Business Practice Standard, not individual standards.
- Modifications to Standard 9 - Requirements for dealing with Redirects on a Firm basis and Standard 10 – Requirements for dealing with Redirects on a Non-Firm Basis to clarify certain standards language and expand the examples.

This recommendation also addresses comments in FERC NOPR Docket No. RM05-5-000 which expressed concern “about some vague language in Standard 10.6, which states that ‘for the purposes of curtailment and other capacity reductions, confirmed Redirects on a Non-Firm basis shall be treated comparably to all other types of Non-Firm Secondary Point-to-Point Service.’”

Attached to this request is a revised Appendix B which the ESS/ITS requests take the place of the current Appendix B of the OASIS Business Practice Standards.

The ESS/ITS is requesting that any necessary changes to the S&CP be postponed until after ratification of the changes to the Business Practices within this recommendation. The reason for this request is to avoid a situation where a Business Practice Standard change is not approved, and the significant work to develop associated implementation standards (S&CP) is wasted.

RECOMMENDED STANDARDS:

Recommended modifications to the WEQ OASIS Business Practice Standards (WEQ BPS-001-000) are redlined below.

Modification 1

Add or edit the following definitions, as appropriate:

> **Commission** – Federal Energy Regulatory Commission, or appropriate regulating authority.
>
> **FERC –** Federal Energy Regulatory Commission.
>
> **Appropriate Regulating Authority** – the entity which has regulating authority over a given Transmission Provider.

Modification 2

Standard 1 changed to read, in part:

> Applicability:
>
> Standard 1 applies to any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce and to transactions limited to the provision of open access transmission service performed under the pro forma tariff required under currently applicable regulations.

Modification 3

Standard 3.1 changed to read, in part:

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant
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> 3.1 ~~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 or providing false information may be denied access by a transmission provider to that transmission provider's OASIS node.

Modification 4

Standard 2.5 changed to read, in part:

> **Other Service Attribute Values**
>
> ~~The Commission has defined s~~Six ancillary services ~~in Order No. 888.~~ are pre-defined. Other services may be offered pursuant to filed tariffs.
>
> 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 Standard 3 for registration requirements.)
>
> ~~**FERC**~~ **Ancillary Services Definitions**

Modification 5

> 4.1. ~~Consistent with FERC policy and regulations, a~~All reservations and price negotiations shall be conducted on OASIS.

Modification 6

Standard 7 changed to read, in part:

> **Introduction**

The standards in this section apply to the offering of Next Hour Market (NHM) Service only. The FERC~~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.

Modification 7

10.1.5. Requests for Redirects on a Non-Firm basis shall specify: ~~the following transmission service attributes in their request:~~

SERVICE_INCREMENT=HOURLY
TS_CLASS=SECONDARY
TS_TYPE=POINT_TO_POINT
TS_PERIOD=FULL_PERIOD
TS_WINDOW=FIXED
~~TS_PERIOD, TS_WINDOW,and SERVICE_INCREMENT shall specify any valid value offered by the TP for Non-Firm Point-to-Point service.~~

Modification 8

10.5.3. The TC shall have the right to request the TP to release unscheduled capacity associated with a confirmed request to Redirect on a Non-Firm basis and reinstate that capacity to the Parent (Firm) Reservation. The TP shall honor all such valid requests, and reinstate the capacity on the Parent Reservation. ~~such that it may subsequently be scheduled, Redirected on a Firm or Non-Firm basis to a different path, resold, etc.~~

Modification 9

9.5.2. The TC ~~shall~~ should withdraw any request to Redirect on a Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect). The TP shall have the right to withdraw their acceptance of any request to Redirect on a Firm basis that

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant
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cannot be confirmed due to limitations in the Capacity Available to Redirect by setting the OASIS standard STATUS data element to the value of SUPERSEDED.

Modification 10

10.5.2. The TC ~~shall~~ should withdraw any request to Redirect on a Non-Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect). The TP shall have the right to withdraw their acceptance of any request to Redirect on a Non-Firm basis that cannot be confirmed due to limitations in the Capacity Available to Redirect by setting the OASIS standard STATUS data element to the value of SUPERSEDED.

Modification 11

9.1.3. A request to Redirect on a Firm basis shall be queued and ~~treated~~ evaluated in the same manner (i.e., same service priority) as any other F~~f~~irm P~~p~~oint to P~~p~~oint request, subject to the other requirements of this standard.

~~10.1.3. A request to Redirect on a Non-Firm basis shall be queued and treated in the same manner as any other non-firm point to point request, subject to the other requirements of this standard.~~

Modification 12

New Business Practice Standard:

10.8.x. If the e-Tag is terminated prior to its original stop time, the TP shall consider this equivalent to a release request by the TC and reinstate capacity on the Parent Reservation.

Modification 13

10.8.6. Once an ~~ETAG~~ e-Tag designating 1-NS service becomes ~~implemented~~ Implemented, the TP shall consider the associated Redirect request(s) to be confirmed. Prior to or coincident with the tag becoming Implemented, the TP shall post the Redirect on OASIS.

Modification 14

New Business Practice Standards:

9.4.x. If the TP determines that only a portion of the requested capacity can be accommodated, the TP shall extend to the TC that portion of the capacity (i.e., partial service) that can be accommodated through a COUNTEROFFER.

10.4.x. If the TP determines that only a portion of the requested capacity can be accommodated, the TP is not obligated to extend to the TC that portion of the capacity (i.e., partial service) that can be accommodated.

Modification 15

4.19. Prior to Confirmation, ~~I~~in those cases where right-of-first refusal is required to be offered, the Transmission Provider shall move requests in the ACCEPTED state to COUNTEROFFER, to notify the Customer~~, through the use of a COUNTEROFFER,~~ of the opportunity to match the subsequent offer.

4.20. A Customer who has been extended a right-of-first-refusal according to Table 4-3 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.

Modification 16

This recommendation is in response to the FERC NOPR RM05-5 requesting clarification:

10.6. For the purposes of curtailment and other capacity reductions, confirmed Redirects on a Non-Firm (Secondary) basis shall have a lower priority than any ~~be treated comparably to all other types of~~ Non-Firm ~~Secondary~~ Point-to-Point Transmission Service.

Modification 17

Miscellaneous recommended changes to Standard 9:

Strike the last sentence in Standard 9.4.2, “An example is shown in Appendix B” as no longer applicable.

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9.5. Upon confirmation of the request to Redirect on a Firm basis, the Capacity Available to Redirect shall be reduced by the amount of the redirected capacity granted for the time period of that Redirect. An example is shown in Appendix B.

10.5. Upon confirmation of the request to Redirect on a Non-Firm basis, the Capacity Available to Redirect shall be reduced by the amount of the redirected capacity granted for the time period of that Redirect. An example is shown in Appendix B.

Modification 18

Change the term “ETAG” to “e-Tag” throughout Standards 9 and 10.

4. SUPPORTING DOCUMENTATION

a. Description of Request:

The comments in Request R04035 proposed, in Summary:

- Changes to some of the definitions, including the replacing references to the "Commission," with an international, more general term, and others.
- Section 4.19 of the OASIS Baseline Business Practices be clarified to reflect that the Transmission Provider is not required to COUNTEROFFER a confirmed reservation.
- The standard be clarified to show that its numbered components are "requirements" of the OASIS Business Practice Standard, not individual standards

Request R05002 was a request to review the Redirect Standard Requirements 9.5 and 10.5 and update the examples to aid in clarifying the provisions of these Standards.

b. Description of Recommendation:

See the WEQ Electronic Scheduling Subcommittee and OASIS 1A Task Force meeting minutes and other documents at www.naesb.org for supporting documentation posted for meetings and conference calls from the following dates:

ESS Subcommittee	OASIS 1A Task Force
October 27, 2005	August 18, 2005
October 20-21, 2005	August 2, 2005
August 31 – September 1, 2005	July 22, 2005
July 13-14, 2005	July 8, 2005
May 11-12, 2005	
April 26, 2005	
January 12-13, 2005	

c. Business Purpose:

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant
Requesters: ESS/ITS
Request Number: R04035 & R05002
Request Title: Request to Modify Standards & Revision of Redirect Standards 9 and 10

See Section d. Commentary/Rationale

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

The following is a list of comments and questions raised by requests R04035 and R05002 and a response to each.

I. Comments on Baseline Business Practices (R04005-A)

a. Comments by Entergy

Submitted by: Edward Davis
September 20, 2004

Entergy suggests that expansion of the Pro Forma Tarrif and OASIS requirements since the initial issuances make the following wording not specific to the provision of transmission service. Therefore, we suggest the following changes to the draft:

"Standard 1: Provision of Open Access Transmission Service. All transmission providers shall provide open access transmission service in accordance with the following requirements.

Applicability

Standard 1 applies to any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce and to transactions limited to the provision of open access transmission service performed under the pro forma tariff required under currently applicable regulations."

Response: Language included as suggested, see modification 2.

Entergy suggests expanding the legitimate reasons for denying access to include the provision of false information, as follows:

a. 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 or providing false information may be denied access by a transmission provider to that transmission provider's OASIS node.

Response: Language included as suggested, see modification 3.

b. Comments by WE Energies

For all documents, definition of terms should be consistent with the NAESB Glossary and between documents. Inconsistencies were found in the definition of Affiliate, Transmission Customer, Firm Transmission, Non-firm Transmission, Point-to-Point Transmission Service, Network Service .

P. 10 of R04005-A, Standard 1.8 - A definition of "significant amount" is needed.
Thank you for the opportunity to comment.

Barb Kedrowski , Project Manager , We Energies

Response: The subcommittee does not have a recommendation at this time. It would be difficult to establish a single number that would be relevant for all OASIS sites.

c. Comments by V. Bissonnette, Hydro-Quebec TransEnergie

HYDRO-QUÉBEC TRANSÉNERGIE COMMENTS
September 20, 2004

NAESB must prepare Business Standards that could apply internationally, meaning to Canadian entities also. This requires some adaptation work to this Recommendation.
The term "Commission" as defined in this Recommendation refers to FERC. That term should be replaced by "Appropriate Regulating Authority" (or some other term) and should be defined as the entity which has regulating authority over a given Transmission Provider. The whole document should then be revised with this international intent in mind (for example, this simplifies 1.5(f) that would then apply to "Appropriate regulating authorities staff" and the introduction to Standard 4.1 could be simplified to read only "All reservations and price…." Instead of "Consistent with FERC policy and regulations, all reservations and price…").

Response: The definition of Commission has been broadened to include "Appropriate Regulating Authority". References to FERC have been omitted where

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they are unnecessary. In cases where we do want to refer to the Federal Energy Regulatory Commission specifically, we have used the term FERC. See modifications 4, 5 and 6.

A Transmission Provider is not necessarily a "public utility". The definition should be broadened to include all possibilities and specify that it is used for those who provide Open Access to their electrical transmission System. As written the definition seems to encompass even systems which do not offer such access. The term "interstate" is also limiting regarding the international nature of a Business Standard. We also question that a Transmission Provider is not necessarily operating "interstate" even in the U.S. As a first try, the resulting definition for Transmission Provider could then read: "An entity that owns, operates or control facilities used for the transmission of electric energy and that offers open access transmission service over those facilities".

Response: The requests to change the definition of "Public Utility" and change the term "interstate" is beyond the scope of the Electronic Scheduling Subcommittee/Information Technology Subcommittee. No changes are recommended to the Business Practice Standards.

Submitted by Victor Bissonnette
Délégué commercial
Direction Commercialisation

Hydro-Québec TransÉnergie

II Comments on Multiple Requests (R04006-B)

a. Comments by First Energy

Denial of Service – the act of ~~this is the~~ intentionally or unintentionally ~~degradation of OASIS performance that~~ denying service to other OASIS customers ~~impacts all customer interactions with OASIS~~ by consuming OASIS cyber resources in such a way that OASIS performance is degraded and the market's ability to operate is impeded. (The name didn't fit the definition.)

Queue Hoarding – this is the act, intentionally or unintentionally, of not confirming or withdrawing an accepted service request within the time limit specifed by the e-tag rules, ~~such that it impacts the ability of other willing buyers to secure service in a timely fashion.~~

Response: The definitions of "Denial of Service" and "Queue Hoarding" currently reflect the intended definitions. No changes are recommended to the Business Practice Standard definitions.

Standard 8. Requirements for dealing with multiple, identical transmission service requests.

8.1 Denial of Service - OASIS system administrators or Transmission Providers shall have the right to institute programs for the detection and mitigation of Denial of Service (DoS) ~~attacks~~events based on recognized standard industry practices. (the word attacks here implies an intentional event while the definition states a cause can be unintentional)

8.1.2 The Transmission Provider will have the right to suspend the user's access to the OASIS system when it is determined that the user has casued two or more DoS events.

8.1.3 The user's access to OASIS will be reinstated when they can demonstrate the problem that caused the DoS events has been corrected.

8.2.1 The Transmission Provider will have the right to suspend the user's access to the OASIS system when it is determined that the user has casued two or more Queue Flooding events.

8.2.2 The user's access to OASIS will be reinstated when they can demonstrate the problem that caused the Queue Flooding events has been corrected.

8.3.3 The Transmission Provider will have the right to suspend the user's access to the OASIS system when it is determined that the user has casued two or more Queue Hoarding events.

8.3.4 The user's access to OASIS will be reinstated when they can demonstrate the problem that caused the Queue Hoarding events has been corrected.

Response: The actions to be taken are already part of FERC Regulations and NAESB Standard 1.

b. Comments by Hydro-Quebec TransEnergie

Naesb weq recommendation r04006-B Oasis 1A Enhancements – Multiple Requests
Hydro-québec transénergie comments
November 5, 2004
The term "Commission" is defined as "the Federal Energy Regulatory Commission" and it is used only in "4. SUPPORTING DOCUMENTATION", Section d. Since the NAESB Standards should have an international intent, we propose to remove this definition and replace "Commission" by FERC (as is done elsewhere in the document) in this Section d.

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Response: See modifications 4, 5 and 6.

Our comments on the definition of "Transmission Provider" stated for Recommendation R04005 also apply: A Transmission Provider is not necessarily a "public utility". The definition should be broadened to include all possibilities and specify that it is used for those who provide Open Access to their electric Transmission System. As written the definition seems to encompass even systems which do not offer such access. The term "interstate" is also limiting regarding the international nature of a Business Standard. We also question that a Transmission Provider is not necessarily operating "interstate" even in the U.S. As a first try, the resulting definition for Transmission Provider could then read: "An entity that owns, operates or control facilities used for the transmission of electric energy and that offers open access transmission service over those facilities".

Response: The requests to change the definition of "Transmission Provider" and "Public Utility" and change the term "interstate" is beyond the scope of the Electronic Scheduling Subcommittee/Information Technology Subcommittee.

Remove the "Responsible party", "Reseller" and "Wholesale merchant function" definitions as those terms are not used in the document.

Response: The definitions within the OASIS Business Practice Standards are global, not repeated within each standard. The definitions listed above are all used in the Business Practice Standards even if not used in the Multiple Requests Standard.

Submitted by Victor Bissonnette
Délégué commercial
Direction Commercialisation Hydro-Québec TransÉnergie

c. Comments by Southern Company Bulk Power Operations

Multiple Requests Southern Company Bulk Power Operations
Comments Submitted by: Southern Company's Bulk Power Operations
Dated: 11/08/04; 3:56 PM via email

Redirects and Multiple Submissions

1) Standard 8, Section 8.3.2 references a time limitation imposed by the Transmission Provider in the event of Queue Hoarding. This restriction states "…in no event shall the TP impose such restrictions that would set the confirmation time limit to expire any earlier than 30 minutes before the pro forma scheduling deadline." This restriction puts an undue burden on the TP's and the TC's to approve and accept the rest of the queued reservations within

only a 30 minute window. The Business Practice Standards for OASIS Transactions (Order 638), Standard 4.13 already specifies timing requirements for OASIS requests. Specifically in that standard, Table 4-2 Footnote 2 states "Confirmation time limits are not to be interpreted to extend scheduling deadlines or to override preexemption deadlines." This footnote already allows the TP to set the TC response deadlines to accommodate multiple reservation requests and yet minimize the impacts on scheduling deadlines due to queue hoarding. Therefore, the Southern Company transmission organization ("Southern Company Transmission") recommends that the EC delete this confirmation time limit restriction (i.e., the last sentence in Section 8.3.2) from the standard.

Response: The intent of the standard is to provide certainty for the transmission customer of the confirmation time limit set by the TP.

2) Standard 9, Section 9.8.1 references a calculation for a default charge on a firm redirect and a default credit on the Parent Reservation, "if not addressed in the Transmission Provider's tariff". All tariff rate calculations are submitted by each Transmission Provider to FERC for approval and should not be addressed here. Southern Company Transmission suggests that the EC delete this section (9.8.1) in its entirety.

Response: If a Standard is addressed in a Transmission Provider's tariff, the tariff will always take precedent. If not addressed in the tariff, standard 9.8.1 provides a standard for this rate calculation.

3) Standard 10, Section 10.1.5 needs to be reworded. As presently worded, the standard seems to imply that Transmission Providers might have to offer additional service increments of Secondary Point-to-Point service. Southern Company Transmission suggests that the EC revise the wording "...offered by the TP for Non-Firm Point-to-Point service." to "…offered by the TP for Non-Firm **Secondary** Point-to-Point service." (emphasis added).

Response: We agree that this could be ambiguous and have made deletions as shown in Modification 7 above.

4) Standard 10, Section 10.5.3 references a "release" mechanism for Redirect on a Non-Firm basis. This proposed release mechanism has not yet been developed in support of this standard. Given the potential design complications that will likely arise in retrofitting a "release" mechanism into existing OASIS

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applications, as well as the likelihood of further automation requirements for verification of redirect capacity available on the Parent Reservation, Southern Company Transmission suggests that the EC consider a 6 months time frame for implementation of Standard 10. Some reasonable implementation period is necessary for an orderly transition which allows a Transmission Provider to remain in compliance with all applicable standards at any point in time.

Response: Any technical changes will be addressed in a revised S&CP and an accompanying implementation plan as required by the S&CP.

5) Standard 10, Section 10.5.3 needs additional clarification, with respect to the rights and obligations of the TC and TP concerning a request for "release" of a confirmed non-firm redirect reservation. Some redundant wording can also be eliminated, in regard to the future use of the re-instated capacity on the Parent Reservation. Southern Company Transmission suggests that Section 10.5.3 be revised as follows:

10.5.3 – The TC shall have the right to request the TP to release unscheduled capacity associated with a confirmed request to Redirect on a Non-Firm basis and reinstate that capacity to the Parent (Firm) Reservation. The TP shall honor all valid requests for release, and reinstate the released capacity to the Parent Reservation.

Response: We agree. See Modification 8 above.

III. Comments on Redirects (R04006-C)

a. Comments by First Energy

Definitions to be added to the OASIS Business Practice standard

Parent Reservation – ~~an~~ the original, existing, confirmed reservation being modified by a Transmission Customer's request to redirect, reassign, resale, etc.

Response: A Parent Reservation may be not be an original reservation as it may be a Redirect, Resale, or other type of reservation. This change has not been made to the standards.

Business Practices to be added to the OASIS Business Practice standard

Standard 9. Requirements for dealing with Redirects on a Firm basis.

9.1 – The Transmission Customer (TC) shall have the right to request modifications to Points of Receipt and/or Points of Delivery (including source or sink, where required) on a firm basis for a Confirmed Point-to-Point Firm Transmission Service reservation (i.e., Parent Reservation)~~,~~ providing the original path of the transaction is utilized for the Redirect. ~~-~~This will be referred to as a Redirect on a Firm basis.

Response: The requested change is a substantive change that would depart from FERC required industry standard practice. Without a rationale for making such a change, this change cannot be considered.

9.1.3 - A request to Redirect on a Firm basis shall be queued and treated in the same manner as any other firm point to point request providing the original path of the transaction is maintained~~,~~ and subject to the other requirements of this standard.

Response: The requested change is a substantive change that would depart from FERC required current industry practice. Without a rationale for making such a change, this change cannot be considered. However, some wording changes are recommended for clarity to Standard 9.1.3 and 10.1.3 has been deleted in its entirety as it conflicts with Standard 10.1.4 and table 4-3. See Modification 11.

9.1.5 – The TC shall not submit a request for a Redirect on a Firm basis that exceeds the Capacity Available for Redirect.

Response: The suggested standard is not consistent with the intent of the standard, which is why standards 9.5.1 and 9.5.2 are included approved OASIS standards. The suggested standard would conflict with FERC requirements. Without a rationale for making such a change, this change cannot be considered.

9.2 - The TC shall be allowed to request a Redirect on a Firm basis for a portion or all of the Capacity Available to Redirect, even if the transmission scheduling rights on the Parent Reservation have been limited due to outages or other reliability-related events. An example is shown in Appendix B. (Ed – I am of the opinion that the request should be allowed, but a refusal should also be allowed if the request will worsen the reliability condition. However, if a TP sold transmission on a firm basis the entity purchasing the transmission capacity should be able to use the capacity up to the limits provided by a firm reservation such that the TP may be required to shed firm load to load the schedule. I think the bottom line here is that the TP sold transmission capacity that they didn't have if they have to shed firm load to allow the transaction to go forward.)

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Response: Standard 9.2 requires only that the Transmission Customer be allowed to request a certain type of redirect. The standard does not address the Transmission Provider response.

9.4.2 - The TC shall be allowed to submit and have pending multiple requests for Redirects on a Firm basis up to and not exceeding the ~~against the same~~ Capacity Available to Redirect. The TP shall evaluate the requests for Redirects in the order they are received and will confirm only the requests up to and not exceeding the Capacity Available to Redirect.~~The TP shall evaluate each such request with the knowledge that only those requests up to the Capacity Available to Redirect may ultimately be confirmed.~~ An example is shown in Appendix B.

Response: The addition of the language "up to and exceeding the" to standard 9.4.2 is not consistent with the intent of the standard. It would achieve the same thing as adding the suggested standard 9.1.5, which was not incorporated. The suggested standard would conflict with FERC requirements. Without a rationale for making such a change, this change cannot be considered. The intent of the change to the sentence "The TP shall evaluate…" is addressed sufficiently elsewhere in the standard.

9.5 - Upon confirmation of the request or requests to Redirect on a Firm basis, the Capacity Available to Redirect shall be reduced by the amount of the total of the redirected capacity for the time period of that Redirect. An example is shown in Appendix B.

Response: Standard 9.5 as written is more concise than the suggested changes. The standard may apply to more than one request which would achieve the same thing as the modified language.

10.1.7 – The TC shall not submit a request for a Redirect on a non-Firm basis that exceeds the Capacity Available for Redirect.

Response: See response to suggested standard 9.1.5 and suggested changes to standard 9.4.2.

10.4.2 - The TC shall be allowed to submit and have pending multiple requests for Redirects on a Non-Firm basis up to and not exceeding the ~~against the same~~ Capacity Available to Redirect. The TP shall evaluate the requests for Redirects in the order they are received and will confirm only the requests up to and not exceeding the Capacity Available to Redirect~~. The TP shall evaluate each such request with the knowledge that only those requests up to the Capacity Available to Redirect may ultimately be confirmed.~~ An example is shown in Appendix B.

Response: See response to suggested standard 9.1.5 and suggested changes to standard 9.4.2.

Appendix B – Redirect Standards Examples

These examples need a lot of work. They do not clearly represent the principles described in 9 and 10 above. These examples would be clearer if they included the parent reservation prior to the redirect, the redirect, and then the effect of the redirect on the parent reservation. Sort of a before and after or cause and effect view.

Response: See updated examples.

b. Comments by Southern Company Bulk Power Operations

Dated: 11/08/04; 3:56 PM via email
Redirects and Multiple Submissions

1) Standard 8, Section 8.3.2 references a time limitation imposed by the Transmission Provider in the event of Queue Hoarding. This restriction states "…in no event shall the TP impose such restrictions that would set the confirmation time limit to expire any earlier than 30 minutes before the pro forma scheduling deadline." This restriction puts an undue burden on the TP's and the TC's to approve and accept the rest of the queued reservations within only a 30 minute window. The Business Practice Standards for OASIS Transactions (Order 638), Standard 4.13 already specifies timing requirements for OASIS requests. Specifically in that standard, Table 4-2 Footnote 2 states "Confirmation time limits are not to be interpreted to extend scheduling deadlines or to override preexemption deadlines." This footnote already allows the TP to set the TC response deadlines to accommodate multiple reservation requests and yet minimize the impacts on scheduling deadlines due to queue hoarding. Therefore, the Southern Company transmission organization ("Southern Company Transmission") recommends that the EC delete this confirmation time limit restriction (i.e., the last sentence in Section 8.3.2) from the standard.

Response: See responses to earlier comments.

2) Standard 9, Section 9.8.1 references a calculation for a default charge on a firm redirect and a default credit on the Parent Reservation, "if not addressed in the Transmission Provider's tariff". All tariff rate calculations are submitted by each Transmission Provider to FERC for approval and should not be addressed here. Southern Company Transmission suggests that the EC delete this section (9.8.1) in its entirety.

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Response: See responses to earlier comments.

3) Standard 10, Section 10.1.5 needs to be reworded. As presently worded, the standard seems to imply that Transmission Providers might have to offer additional service increments of Secondary Point-to-Point service. Southern Company Transmission suggests that the EC revise the wording "...offered by the TP for Non-Firm Point-to-Point service." to "…offered by the TP for Non-Firm **Secondary** Point-to-Point service." (emphasis added).

Response: See responses to earlier comments.

4) Standard 10, Section 10.5.3 references a "release" mechanism for Redirect on a Non-Firm basis. This proposed release mechanism has not yet been developed in support of this standard. Given the potential design complications that will likely arise in retrofitting a "release" mechanism into existing OASIS applications, as well as the likelihood of further automation requirements for verification of redirect capacity available on the Parent Reservation, Southern Company Transmission suggests that the EC consider a 6 months time frame for implementation of Standard 10. Some reasonable implementation period is necessary for an orderly transition which allows a Transmission Provider to remain in compliance with all applicable standards at any point in time.

Response: See responses to earlier comments.

5) Standard 10, Section 10.5.3 needs additional clarification, with respect to the rights and obligations of the TC and TP concerning a request for "release" of a confirmed non-firm redirect reservation. Some redundant wording can also be eliminated, in regard to the future use of the re-instated capacity on the Parent Reservation. Southern Company Transmission suggests that Section 10.5.3 be revised as follows:

10.5.3 – The TC shall have the right to request the TP to release unscheduled capacity associated with a confirmed request to Redirect on a Non-Firm basis and reinstate that capacity to the Parent (Firm) Reservation. The TP shall honor all valid requests for release, and reinstate the released capacity to the Parent Reservation.

Response: See responses to earlier comments.

c. Comments by WE Energies

Comments Submitted by: Barb Kedrowski

Dated: 11/11/04, 1:21 PM
Below are We Energies' comments on the WEQ 2004 Annual Plan Item 2 - OASIS 1A Enhancements - Redirects (Comments in red, text from standard in blue): [color deleted]

Standard 10 - Requirements for dealing with Redirects on a non-firm basis:

Section 10.1.6 - Requests for redirects on a non-firm basis shall be submitted by the TC as pre-confirmed.

We Energies' comment: Why must it be preconfirmed? Would it be possible to set an acceptable time interval for redirect request confirmation that would allow requests to be submitted without being preconfirmed? Sometimes deals are done that encompass more than one transmission provider. If TLR's are in effect on one TP's jurisdiction, the deal falls apart. If the redirect request is preconfirmed and it has been confirmed by the TP, it is no longer of any use since one segment of the deal can't flow.

Response: The preconfirmation requirement was accepted because the Transmission Customer has the ability to use the release mechanism, per standard 10.5.3, to "undo" the transaction, or move the capacity back to the parent reservation. Specifics of the release mechanism are being developed in Recommendation R04006-C1.

Section 10.5.1 - The TC shall not confirm any request to Redirect on a non-firm basis that would exceed the Capacity Available to Redirect at that point in time. The TP shall have the right to block any such confirmation.

We Energies' comment: If the TC can submit multiple redirect requests that are over the level of the parent request, how does the TC know if they have excluded the capacity available to redirect if the TP is evaluating multiple requests?

Response: Evaluate the multiple Redirect requests in queue order and accept those requests up the capacity available to redirect. Any additional requests are held pending until the disposition of the prior requests are determined.

Sections 10.1.6 and 10.5.1
We Energies comment: When looking at these sections together, if a TC must pre-confirm a request and can have multiple competing redirect requests

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that are being evaluated, when the TC "accepts" a request it will automatically be confirmed in violation of 10.5.1. This then raises the question on how the TC would notify the TP which competing redirect request has priority if more than one are deemed Ok. If the requirement for pre-confirmation is removed, then the TC would be able to determine which request they would prefer to confirm.

Response: We do not agree that preconfirmation will result in a violation of 10.5.1. Based on 10.5, the violation would not occur. The Transmission Provider would reject any requests over the amount of the Capacity Available to Redirect of the Parent Reservation. The subcommittee discussed this issue at length and determined not to remove the requirement for preconfirmation.

Section 4.b Description of Recommendation (Supporting Documentation)
We Energies' comment: Use of the word "an" instead of the word "and" in the sentence: "Only the primary transmission provider is in a position to make such an assessment and authorize the redirected service under the OATT."

Response: Noted.

Thanks,

Barb Kedrowski
Project Manager
We Energies

d. Comments by Puget Sound Energy

Comments Submitted by: Susanne McFadden
Puget Sound Energy Marketing
Dated: 11/10/04; 5:21 PM
REDIRECTS R04006-C

9.5.2 – The TC shall withdraw any request to Redirect on a Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect). The TP shall have the right to withdraw their acceptance of any request to Redirect on a Firm basis that cannot be confirmed due to limitations in the Capacity Available to Redirect by setting the OASIS standard STATUS data element to the value of SUPERSEDED. (The TC should not have to go in and remove all the Accepted requests if the capacity to redirect is depleted. TP's OASIS should automatically supercede remaining requests.)

Response: We agree. See modification 9.

9.6.2 - Curtailments or other capacity reductions affecting the reserved capacity on the Redirect reservation shall not affect the Parent Reservation nor result in a reinstatement of capacity on the Parent Reservation. (…result in the automatic reinstatement… Should alos inclued "unless the TC submits a subsequent Redirect on a Firm Basis request")

Response: The intent of this standard is to not allow any reinstatement, automatic or otherwise. 9.6.2 is intended to only address curtailments and other capacity reductions.

10.1.3 - A request to Redirect on a Non-Firm basis shall be queued and treated in the same manner as any other non-firm point to point request, subject to the other requirements of this standard. (What does this imply? The TC is requesting secondary point- to-point service, not non-firm point-to-point service. It is a "as available" service subordinate to all other services (exception is Buy At Market))

Response: We agree. See Modification 11.

10.1.6 – Requests for Redirects on a Non-Firm basis shall be submitted by the TC as pre-confirmed. (Why pre-confirmed? This limits a customer's options.)

Response: Refer to response to We Energies' comments on this standard.

10.5 - Upon confirmation of the request to Redirect on a Non-Firm basis, the Capacity Available to Redirect shall be reduced by the amount of the redirected capacity for the time period of that Redirect. An example is shown in Appendix B. (OATT says in 22.1(3) the TC shall retain all of their scheduling rights on the parent. This statement limits the TC.)

Response: The release mechanism was created to allow the customer flexibility.

10.5.1 – The TC shall not confirm any request to Redirect on a Non-Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect). The TP shall have the right to block any such confirmation.

10.5.2 – The TC shall withdraw any request to Redirect on a Non-Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect).

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The TP shall have the right to withdraw their acceptance of any request to Redirect on a Non-Firm basis that cannot be confirmed due to limitations in the Capacity Available to Redirect by setting the OASIS standard STATUS data element to the value of SUPERSEDED. (The TC should not have to go in and remove all the Accepted requests if the capacity to redirect is depeleted. TP's OASIS should automatically supercede remaining requests.)

Response: We agree. See modification 10.

10.5.3 – The TC shall have the right to request the TP to release capacity associated with a confirmed request to Redirect on a Non-Firm basis and reinstate that capacity to the Parent (Firm) Reservation. The TP shall honor all such requests, and reinstate the capacity on the Parent Reservation such that it may subsquently be scheduled, Redirected on a Firm or Non-Firm basis to a different path, resold, etc. (OATT says in 22.1 (3) the TC shall retain all of their scheduling rights on the parent. This statement limits, the TC has to request to have their rights back.)

Response: The release mechanism was created to allow the customer flexiblity.

10.8 - TPs shall have the right, but are in no means obligated, to accept requests for Redirect on a Non-Firm basis based on the submission of an Electronic Tag (ETAG) using protocols compliant with Version 1.7.095 NERC Transaction Information System Working Group (TISWG) *Electronic Tagging Functional Specification*. (If a TC can use E-Tag to request a Redirect on a Non-firm Basis, then the TC should also have the ability "release" capacity via E-Taf by referencing the parent reservation.)

Response: See Modification 12.

10.8.5 - The OASIS queue time of a Redirect requested via ETAG shall be the TP's ETAG Approval Service receipt time, unless a system failure requires the use of backup procedures, in which case the OASIS queue time shall be the time the ETAG is received by the TP. (How is the TP going to force the appearance and specified queue time into their OASIS?. How can this be comparable if some requests are on OASIS and other are off-OASIS)

Response: See Modification 13.

9.4.x Should there be an explicit requirement that if there is insufficient capacity to support the redirect either due to TPs limited ATC or TCs limited Capacity

Available to Redirect that the TP must or may COUNTEROFFER with only the capacity that can be granted to the redirect?

Response: See Modification 14 which adds Standards 9.4.3 and 10.4.3 which require the TP to COUNTEROFFER only in the case of a Redirect on a Firm Basis (Standard 9) but not in the case of a Redirect on a Non-Firm Basis (Standard 10).

9.5.1/10.5.1 Should the TC obligations regarding "shall not confirm" be changed to "should". The TP has the right to block confirmation. Should this be restated as allowing the TP to "block or annul" confirmation. Blocking may imply a requirement to modify OASIS software implementations, while setting status to ANNULLED will functionally accomplish the same thing – can't hold a confirmed redirect on firm basis in excess of Capacity Available to Redirect.

Response: We do not agree. It is important that the TC not confirm a Redirect that exceeds the capacity available to Redirect. No change has been made to the standards.

9.5.2/10.5.2 Should the TCs obligation to withdraw be changed from a "shall" to a "should".

Response: See Modifications 9 and 10.

Examples: Provide better examples to clarify the Redirect Standard including revisions as necessary based on any proposed changes to this Standard.

Response: Agree. Revised examples provided. See revised Appendix B to the OASIS Business Practice Standards.

The WEQ ESS/ITS requested that Section 4.19 of the OASIS Baseline Business Practices be clarified to reflect the Transmission Provider is not required to COUNTEROFFER a confirmed reservation.

Response: See Modification 15. The change to Standard 4.19 clarifies that a request cannot be moved to a state of Counteroffer once confirmed. A clarification was also made to Standard 4.20 to clarify that Standard 4.20 does not apply in the case where a customer has been extended the right-of-first-refusal for rollover rights.

Clarification that the numbered components are "requirements" of the OASIS Business Practice Standard, not individual standards.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant
Requesters: ESS/ITS
Request Number: R04035 & R05002
Request Title: Request to Modify Standards & Revision of Redirect Standards 9 and 10

Response: This issue is no longer relevant and the business practice standards will remain as they exist.

WEQ ESS/ITS 10/27/05

The following motion was made at the October 27, 2005 WEQ ESS/ITS Conference call:

To send Recommendation R04035/R05002 to the Executive Committee for adoption.

The vote was unanimous with five participants attending.

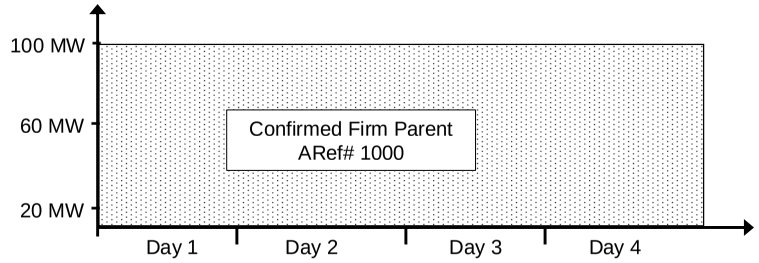
Recommended Appendix B
Redirect Standards Examples
(to replace existing Appendix B)

Notes for Examples: In all cases a Parent Reservation to be Redirected must be Firm Point-to-Point. Unless noted otherwise, example Redirect requests may be on either a firm or non-firm basis. Capacity that is shaded (dotted) shows Parent Capacity Available to Redirect. Capacity in Gray is not available to Redirect. Requests that are cross-hatched are outside the bounds of the Parent Reservation.

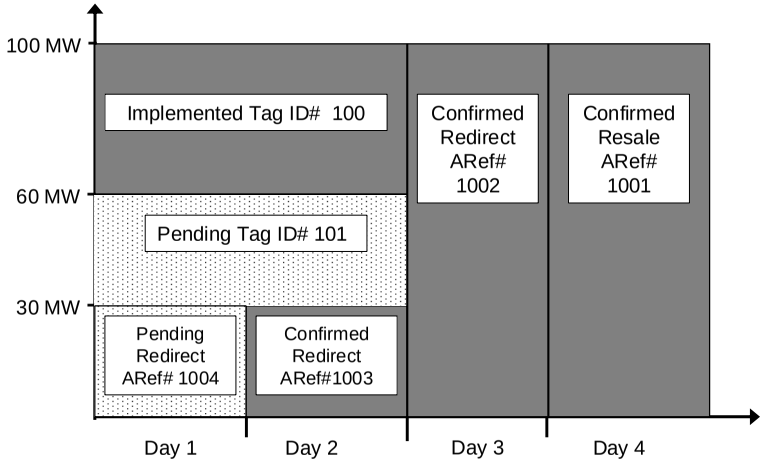
Parent Capacity Available to Redirect

Parent Capacity Unavailable to Redirect

Requested Capacity outside the bounds of the Parent Reservation

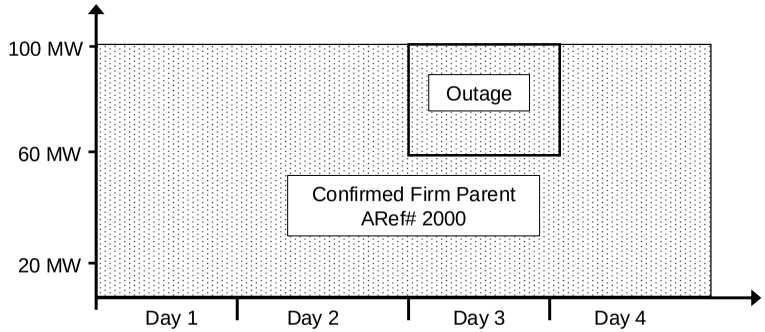


Example 1: Parent Reservation



Example 1: Parent Capacity Available to Redirect after various Events

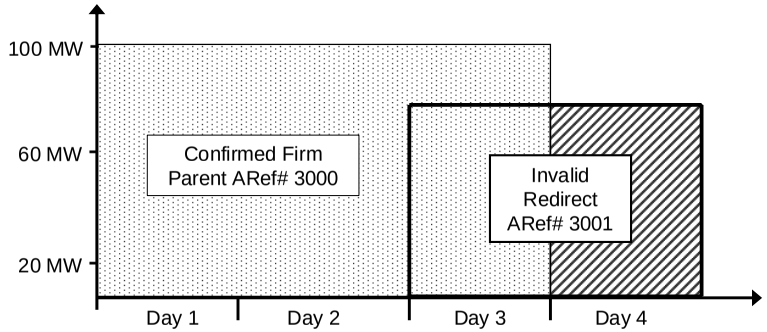
Example 1 – Capacity Available to Redirect against Parent ARef# 1000 would be 60 MW for day one, 30 MW for day two and zero MW for days 3 and 4. See Standards 9.4, 9.5, 10.4 and 10.5 and definition of Capacity Available to Redirect.



Example 2: Parent Capacity Available to Redirect Not Affected by Outage

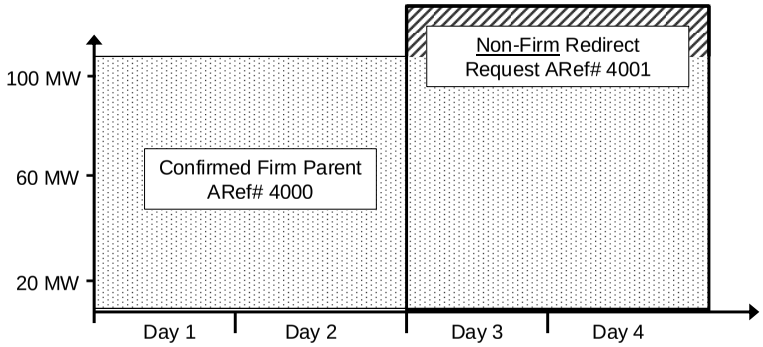
Example 2 – The Capacity Available to Redirect is unaffected by the outage. The Capacity Available to Redirect against Parent ARef# 2000 would be 100 MW's for all four days. See Standards 9.2 and 10.2.

RECOMMENDATION TO NAESB WEQ EXECUTIVE COMMITTEE
Requesters: **Electronic Scheduling Subcommittee and Information Technology Subcommittee**
Request No.: **R05002**
Request Title: **Revision of Redirect Standards 9 and 10**



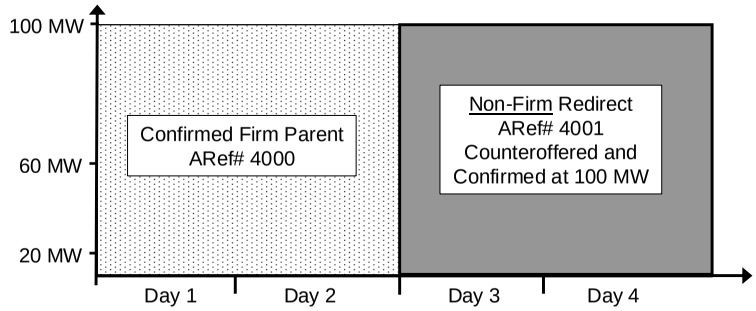
Example 3: Redirect Request with Invalid Time Period

Example 3 – The TP must deny Request 3001 because the time period is invalid (i.e. extends past the time period of the Parent Reservation). The Capacity Available to Redirect on the Parent Reservation remains at 100 MW for the duration of the reservation. See Standards 9.3, 9.4.1, 10.3 and 10.4.1



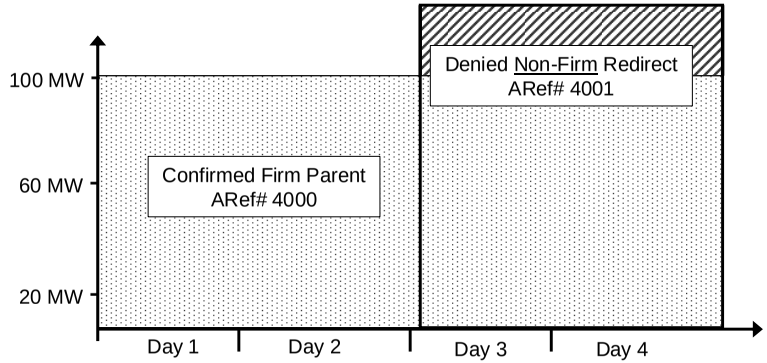
Example 4: Non-Firm Redirect with Capacity Requested exceeding Capacity Available to Redirect on Parent Reservation.

Example 4 – With a Non-Firm Redirect Request where the capacity requested exceeds the Capacity Available to Redirect of the Parent, if ATC is available, the TP may Counteroffer ARef# 4001 at 100 MW (See Example 4a) or deny ARef# 4001 (See Example 4b). In 4a, assuming the customer confirmed the Counteroffer, the Capacity Available to Redirect on Parent Reservation ARef# 4000 would be 100 MW for the first two days and zero for days 3 and 4. See Standards 10.4 and 10.5.



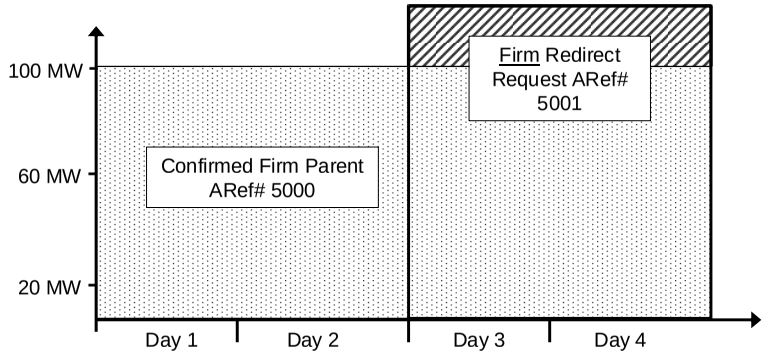
Example 4a: Non-Firm Redirect with Optional Counteroffer.

RECOMMENDATION TO NAESB WEQ EXECUTIVE COMMITTEE
Requesters: Electronic Scheduling Subcommittee and Information Technology Subcommittee
Request No.: R05002
Request Title: Revision of Redirect Standards 9 and 10



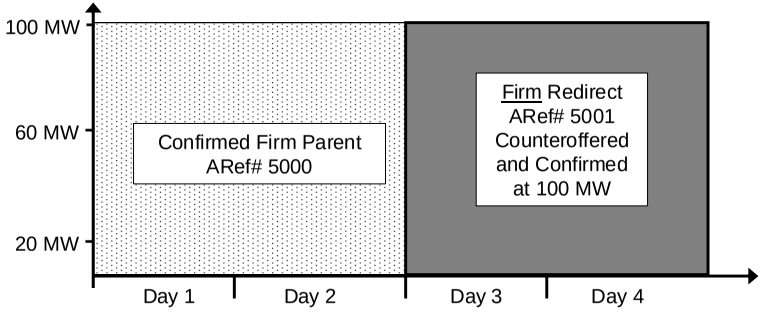
Example 4b: Non-Firm Redirect with Optional Deny.

Example 4b – In this scenario, the TP denied the Non-Firm Redirect ARef# 4001. The Capacity Available to Redirect on Parent Reservation ARef# 4000 remains 100 MW for all four days. The TP could also Counteroffer Request 4001 at 100 MW (See Example 4a). See Standard 10.4.3.



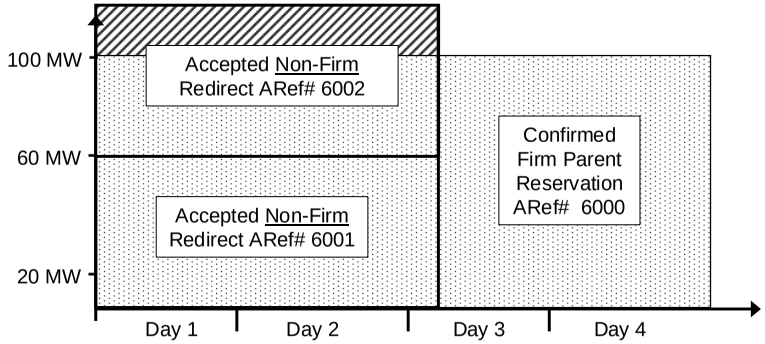
Example 5: Firm Redirect with Capacity Requested exceeding Capacity Available to Redirect on Parent Reservation.

Example 5 - With a Firm Redirect Request where the capacity requested exceeds the Capacity Available to Redirect of the Parent, assuming ATC is available, the TP must Counteroffer ARef# 5001 at 100 MW. Assuming also that the customer confirmed the Counteroffer, the Capacity Available to Redirect on Parent Reservation ARef# 5000 would be 100 MW for the first two days and zero for days 3 and 4. See Standard 9.4.3.

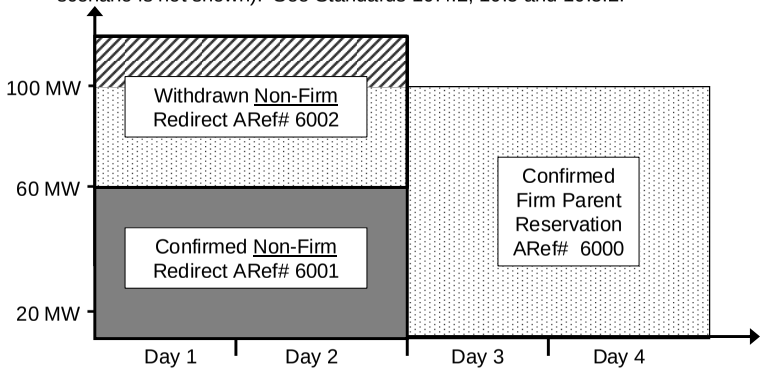


Example 5: Firm Redirect with Counteroffer

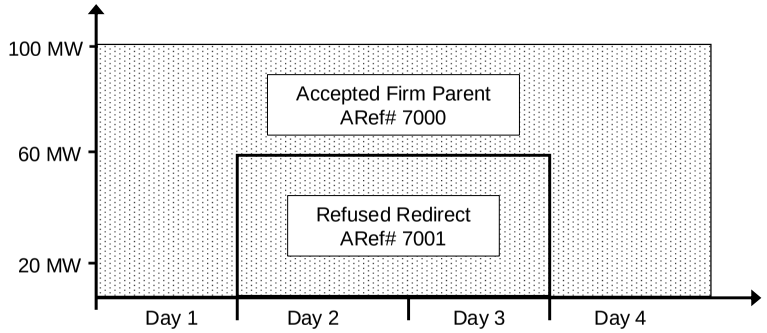
RECOMMENDATION TO NAESB WEQ EXECUTIVE COMMITTEE
Requesters: **Electronic Scheduling Subcommittee and Information Technology Subcommittee**
Request No.: **R05002**
Request Title: **Revision of Redirect Standards 9 and 10**



Example 6 – Multiple requests for Firm or Non-Firm Redirects may be pending against the same Capacity Available to Redirect. Once Request 6001 is Confirmed, Non-Firm ARef#6002 may be Refused by the TP or Withdrawn by the Customer. The Capacity Available to Redirect on ARef# 6000 is 40 MW for days 1 and 2. (The TP could also Counteroffer non-firm ARef# 6002. This scenario is not shown). See Standards 10.4.2, 10.5 and 10.5.2.



Example 6: Multiple Requests against same Capacity



Example 7: Redirect Parent Reservation must be Confirmed

Example 7 – The Customer may only Redirect against capacity of a reservation that is in a Confirmed State. ARef# 7001 would be Refused and the Capacity Available to Redirect against Parent ARef# 7000 would be zero MW's for all four days because the reservation is not Confirmed. See Standards 9.1.1 and 10.1.1.

Workpaper
Consolidation of recommendations R05002 and R04035
to see resulting
Standards 9 and 10[1].

Standard 9. Requirements for dealing with Redirects on a Firm basis.

9.1. The Transmission Customer (TC) shall have the right to request modifications to Points of Receipt and/or Points of Delivery (including source or sink, where required) on a firm basis for a Confirmed Point-to-Point Firm Transmission Service reservation (i.e., Parent Reservation). This will be referred to as a Redirect on a Firm basis.

9.1.1. The TC may Redirect on a Firm basis any confirmed Firm Point-to-Point Parent Reservation regardless of the request type.

9.1.2. A request to Redirect on a Firm basis shall be submitted to the primary Transmission Provider with a request type of REDIRECT.

9.1.3. A request to Redirect on a Firm basis shall be queued and ~~treated~~ evaluated in the same manner (i.e., same service priority) as any other ~~f~~Firm ~~p~~Point to ~~p~~Point request, subject to the other requirements of this standard.

9.1.4. No additional deposit shall be required for a request to Redirect on a Firm basis.

9.2. The TC shall be allowed to request a Redirect on a Firm basis for a portion or all of the Capacity Available to Redirect, even if the transmission scheduling rights on the Parent Reservation have been limited due to outages or other reliability-related events. An example is shown in Appendix B.

9.3. The TC shall be allowed to request a Redirect on a Firm basis for a portion or all of the time period of the Parent Reservation (i.e., bound by the start/stop times of the Parent Reservation). An example is shown in Appendix B.

9.3.1. A request for Redirect on a Firm basis must be submitted, and is subject to all request timing requirements consistent with a reservation for Firm service of similar duration.

9.3.2. A request for Redirect on a Firm basis must represent an established Firm Point-to-Point Service Increment (e.g., Daily, Monthly, etc.) offered by the Transmission Provider.

9.4. The TC's rights on the Parent Reservation shall remain unaffected during the Transmission Provider evaluation of the request to Redirect on a Firm basis.

9.4.1. If the request to Redirect on a Firm basis is denied for any reason, all rights and obligations shall remain per the Parent Reservation. An example is shown in Appendix B.

[1] This document does not contain changes recommended in R04006D.

9.4.2. The TC shall be allowed to submit and have pending multiple requests for Redirects on a Firm basis against the same Capacity Available to Redirect. The TP shall evaluate each such request with the knowledge that only those requests up to the Capacity Available to Redirect may ultimately be confirmed. ~~An example is shown in Appendix B.~~

9.4.x. If the TP determines that only a portion of the requested capacity can be accommodated, the TP shall extend to the TC that portion of the capacity (i.e., partial service) that ca be accommodated through a COUNTEROFFER.

9.5. Upon confirmation of the request to Redirect on a Firm basis, the Capacity Available to Redirect shall be reduced by the amount of the redirected capacity granted for the time period of that Redirect. An example is shown in Appendix B.

9.5.1. The TC shall not confirm any request to Redirect on a Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect). The TP shall have the right to block any such confirmation. An example is shown in Appendix B.

9.5.2. The TC ~~shall~~ should withdraw any request to Redirect on a Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect). The TP shall have the right to withdraw their acceptance of any request to Redirect on a Firm basis that cannot be confirmed due to limitations in the Capacity Available to Redirect by setting the OASIS standard STATUS data element to the value of SUPERSEDED.

9.5.3. Redirects on a Firm basis shall have all the rights and obligations of an original reservation for Firm service (with the exception of renewal/roll-over rights), including the rights to be Redirected on a Firm and/or Non-Firm basis.

9.6. For the purposes of curtailment and other capacity reductions, confirmed Redirects on a Firm basis shall be treated comparably to all other types of Firm Point-to-Point Service.

9.6.1. Curtailments or other capacity reductions to the remaining portion of the reserved capacity on the Parent Reservation shall not affect the Redirect reservation.

9.6.2. Curtailments or other capacity reductions affecting the reserved capacity on the Redirect reservation shall not affect the Parent Reservation nor result in a reinstatement of capacity on the Parent Reservation.

9.7. Unless otherwise mutually agreed to by the primary provider and original customer, a request for Redirect on a Firm basis does not impact the TC's long term firm renewal rights (e.g., rollover or evergreen rights) on the original path, nor does it confer any renewal rights on the redirected path.

9.8. Any differences in charges associated with the Redirect on a Firm basis will be settled in accordance with the Transmission Provider's tariff.

9.8.1. If not addressed in the Transmission Provider's tariff or in a Service Agreement, a credit on the Parent Reservation shall be computed as the total reservation charge divided by the total megawatt hours reserved times the megawatt hours redirected. The

redirected reservation shall be charged as if it were a reservation with a request type of ORIGINAL.

Standard 10. Requirements for dealing with Redirects on a Non-Firm basis.

10.1. The Transmission Customer (TC) shall have the right to request an alternate, or secondary, Point of Receipt and/or Point of Delivery (including source and sink, if required) on a non-firm basis for a Confirmed Point-to-Point Firm Transmission Service reservation (i.e., Parent Reservation). This will be referred to as a Redirect on a Non-Firm basis.

10.1.1. The TC may Redirect on a Non-Firm basis any confirmed Firm Point-to-Point Parent Reservation regardless of the request type.

10.1.2. A request to Redirect on a Non-Firm basis shall be submitted to the primary Transmission Provider with a request type of REDIRECT.

~~**10.1.3.** A request to Redirect on a Non-Firm basis shall be queued and treated in the same manner as any other non-firm point to point request, subject to the other requirements of this standard.~~

10.1.4~~3~~3. Redirects on a Non-Firm basis shall have a service priority that is lower than non-firm hourly point-to-point service.

10.1.~~5~~4. Requests for Redirects on a Non-Firm basis shall specify~~:~~ ~~the following transmission service attributes in their request:~~

SERVICE_INCREMENT=HOURLY
TS_CLASS=SECONDARY
TS_TYPE=POINT_TO_POINT
TS_PERIOD=FULL_PERIOD
TS_WINDOW=FIXED
~~TS_PERIOD, TS_WINDOW,and SERVICE_INCREMENT shall specify any valid value offered by the TP for Non-Firm Point-to-Point service.~~

10.1.~~6~~5. Requests for Redirects on a Non-Firm basis shall be submitted by the TC as pre-confirmed.

10.2. The TC shall be allowed to request a Redirect on a Non-Firm basis for a portion or all of the Capacity Available to Redirect, even if the transmission scheduling rights on the Parent Reservation have been limited due to outages or other reliability-related events. An example is shown in Appendix B.

10.3. The TC shall be allowed to request a Redirect on a Non-Firm basis for a portion or all of the time period of the Parent Reservation (i.e., bound by the start/stop times of the Parent Reservation). An example is shown in Appendix B.

10.3.1. A request for Redirect on a Non-firm basis must be submitted, and is subject to all request timing requirements consistent with reservations for Non-Firm Point-to-Point service of similar duration.

10.4. The TC's rights on the Parent Reservation shall remain unaffected during the Transmission Provider evaluation of the request to Redirect on a Non-Firm basis.

10.4.1. If the request to Redirect on a Non-Firm basis is denied for any reason, all rights and obligations shall remain per the Parent Reservation. An example is shown in Appendix B.

10.4.2. The TC shall be allowed to submit and have pending multiple requests for Redirects on a Non-Firm basis against the same Capacity Available to Redirect. The TP shall evaluate each such request with the knowledge that only those requests up to the Capacity Available to Redirect may ultimately be confirmed. An example is shown in Appendix B.

10.4.x. If the TP determines that only a portion of the requested capacity can be accommodated, the TP is not obligated to extend to the TC that portion of the capacity (i.e., partial service) that can be accommodated.

10.5. Upon confirmation of the request to Redirect on a Non-Firm basis, the Capacity Available to Redirect shall be reduced by the amount of the redirected capacity granted for the time period of that Redirect. An example is shown in Appendix B.

10.5.1. The TC shall not confirm any request to Redirect on a Non-Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect). The TP shall have the right to block any such confirmation.

10.5.2. The TC ~~shall~~ should withdraw any request to Redirect on a Non-Firm basis that would exceed the Capacity Available to Redirect at that point in time (i.e., at the time of attempted confirmation and over the time interval of the Redirect). The TP shall have the right to withdraw their acceptance of any request to Redirect on a Non-Firm basis that cannot be confirmed due to limitations in the Capacity Available to Redirect by setting the OASIS standard STATUS data element to the value of SUPERSEDED.

10.5.3. The TC shall have the right to request the TP to release unscheduled capacity associated with a confirmed request to Redirect on a Non-Firm basis and reinstate that capacity to the Parent (Firm) Reservation. The TP shall honor all such valid requests, and reinstate the capacity on the Parent Reservation~~, such that it may subsquently be scheduled, Redirected on a Firm or Non-Firm basis to a different path, resold, etc.~~

10.6. For the purposes of curtailment and other capacity reductions, confirmed Redirects on a Non-Firm (Secondary) basis shall have a lower priority than any ~~be treated comparably to all other types of~~ Non-Firm ~~Secondary~~ Point-to-Point Transmission Service.

10.6.1. Curtailments or other capacity reductions to the remaining portion of the reserved capacity on the Parent Reservation shall not affect the Redirect reservation.

10.7. Any differences in charges associated with a Redirect on a Non-Firm basis will be settled in accordance with the Transmission Provider's tariff.

10.7.1. Unless otherwise provided for in the TP's tariff, there shall be no charge to Redirect on a Non-Firm basis.

10.8. TPs shall have the right, but are in no means obligated, to accept requests for Redirect on a Non-Firm basis based on the submission of an Electronic Tag (~~ETAG~~ e-Tag) using protocols

compliant with Version 1.7.095 NERC Transaction Information System Working Group (TISWG) *Electronic Tagging Functional Specification*.

10.8.1. The TC submitting a Redirect on a Non-Firm basis via a tag shall be subject to the same transaction timing requirements specified for submission of such requests directly on OASIS.

10.8.2. A TP accepting Redirects on a Non-Firm basis via ~~ETAG~~ e-Tag shall allow a TC to request redirected service for one or more path segments of the tag by designating:

(a) 1-NS as the transmission product code under the OASIS block,
(b) the OASIS reservation identifier of the Firm Parent Reservation to be redirected, and
(c) the secondary points of receipt and delivery being requested.

10.8.3. A TP accepting Redirects on a Non-Firm basis via ~~ETAG~~ e-Tag shall determine the amount of the redirect request from:

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

10.8.4. A TP accepting Redirects on a Non-Firm basis via ~~ETAG~~ e-Tag shall consider the ~~ETAG~~ e-Tag as a pre-confirmed Redirect request on a Non-Firm basis that is to be processed on a comparable basis with all such requests made directly on OASIS, with all obligations associated with such a request to be borne by the TC holding the Parent Reservation (e.g., any ancillary services, charges or credits for redirect, etc.), and subject to all other requirements of this Standard.

10.8.5. The OASIS queue time of a Redirect requested via ~~ETAG~~ e-Tag shall be the TP's ~~ETAG~~ e-Tag Approval Service receipt time, unless a system failure requires the use of backup procedures, in which case the OASIS queue time shall be the time the ~~ETAG~~ e-Tag is received by the TP.

10.8.6. Once an ~~ETAG~~ e-Tag designating 1-NS service becomes ~~i~~Implemented, the TP shall consider the associated Redirect request(s) to be confirmed. Prior to or coincident with the tag becoming Implemented, the TP shall post the Redirect on OASIS.

10.8.x. If the e-Tag is terminated prior to its original stop time, the TP shall consider this equivalent to a release request by the TC and resinstate capacity on the Parent Reservation.

TO: NAESB WEQ Executive Committee
From: Joel Dison, EC Member, Marketer/Broker Segment, IOU Subsegment

November 29, 2005

Dear EC:

The Electronic Scheduling Subcommittee has done an outstanding job over the last year of working out some very difficult issues related to Business Practices for Resales and Redirects. Southern Company Generation commends the Electronic Scheduling Subcommittee for their accomplishments.

Regrettably, representatives of Southern Company Generation have been unable to participate in recent deliberations within the Electronic Scheduling Subcommittee and were similarly unable to review and provide timely comments on the Redirect standards that are before the Executive Committee today. As a result, these comments are – less than timely. For that, we are deeply apologetic.

Nevertheless, we have reviewed the proposed standards and have discovered a problem with the Redirect standard that is highlighted by the proposed language modifications and the examples. Unfortunately, I must admit that my interpretation of the original language suggests that the problem also exists with the current language as well. As such, I cannot simply recommend a rejection of the proposed modification without also recommending a correction to the original as well.

Southern Company Generation agrees with the Electronic Scheduling Subcommittee that transmission providers should have the right to collect an "uplift" associated with a redirect when that redirect is being made to a "premium" path. We believe this was the intent of the original standard. However, as implemented, the redirect standard not only collects the premium associated with this difference in path, but also collects an uplift associated with any difference in price that is predicated on term of service as well.

The Redirect standard calculates the "premium path uplift" based upon a 7x24 (i.e. hourly) conversion of the originally purchased transmission service as compared to a 7x24 conversion of the posted price of the service on the redirected path for the term of the redirect. The problem, as highlighted in the proposed examples, is introduced whenever the posted rates for shorter term products are calculated on anything other than a 7x24 basis. For example, the table below shows the current posted rates for Annual, Monthly, Weekly, Daily, and Hourly service for the Southern Companies:

	Yearly	Monthly	Weekly	Daily
Posted Rate	$21.58908/kw-yr	$1.79909/kw-Mo	$0.4152/kw-Wk	$0.08303/kw-Day
7x24 Rate	$2.46451/MWH	$2.46451/MWH	$2.47125/MWH	$3.45958/MWH
5x16 Rate	$5.18969/MWH	$5.18969/MWH	$5.18969/MWH	$5.18938/MWH

Using a conversion rate that is based on a 7x24 rate as proposed in the Redirect standard will result in uplift associated with "term of service", even if the posted rates on the two paths are the same for a given term of service.

It has long been Southern Company Generation's belief that such differences in rates associated with term of service were built to encourage transmission customers to purchase longer-term service products. A transmission customer should not, therefore, be dissuaded from purchasing a longer-term service product by removing these incentives within the Redirect Business Practices. Southern Company Generation does not believe this was the intention of the Electronic Scheduling Subcommittee. If it is, Southern Company disagrees with that intent and would recommend that all transmission customers voice similar disagreement. Regardless, Southern Company Generation must recommend that the Executive Committee not pass the redirect standard modifications as proposed.

As mentioned above, however, we have determined that this flaw in the Redirect standard exists not just in the proposed modifications, but in the original language as well. As such, Southern Company Generation has taken the initiative to develop replacement language that it feels satisfies the original intent. The language that Southern Company Generation has developed proposes that the Redirect standard charge this "premium path uplift" based upon difference in posted rate between the original and redirected paths at the time of the redirect for the period of the redirect. That replacement language, along with replacement settlement examples, is attached to this memo.

In conclusion, Southern Company Generation cannot support the proposed modifications to the Redirect standards. Instead, Southern Company Generation puts forth a replacement recommendation for consideration of the Executive Committee. If this replacement cannot be adopted, then Southern Company Generation would most likely vote against the proposed modifications.

As always, thank you for your Consideration

Sincerely,

Joel

Joel Dison
Southern Company Generation

Replacement language for Redirect Modifications and Settlement Examples

Modification to Redirect Standards

9.8.1 If not addressed in the Transmission Provider's tariff or in a Service Agreement, any difference in charges associated with the Redirect on a Firm basis will be the responsibility of the TC submitting the Redirect. The difference shall be calculated as the difference in the posted rate at the time of the Redirect on the Redirected path and the posted rate at the time of the Redirect for original path for the term of the Redirect.

Additions to Redirect Standard Examples

The following additions will be included in the Redirect Standard Examples to illustrate the implementation of the revised Standard 9.8.1

Redirect Settlement Example 1 (note: this is a new example):
TC1 purchases Yearly Firm service from the TP at a rate of $24,476/MW-Year, which is an equivalent daily rate (on a 7 day/week basis) of $24,476/52/7 = $67.24/MW-Day. The TP posts Daily Firm service on a 5 day/week basis. For the original path, this is posted at $24,476/52/5 = $94.13/MW-Day for every day of the year. TC1 submits and confirms a Redirect on a firm basis for April 25, 2005. The Daily Firm rate on the Redirected path is also posted at $94.13/MW-Day. There would be no charge associated with this Redirect.

Redirect Settlement Example 2:
TC1 purchases Monthly Firm service from the TP at a rate of $2035/MW-Month for the months of February and March of 2005, which is an equivalent weekly rate of $2035*12/52 = $469.62/MW-Week. TC1 submits and confirms a Redirect on a firm basis for the week of Feb 28 through March 7, 2005. The Weekly Firm rate on the redirected path as posted for that week is $476.10/MW-Week. The Weekly Firm rate on the original path as posted for that week is $469.62/MW-Week. The difference in service due on the Redirect would be computed at $476.10/MW-Week less $469.62/MW-Week or $6.48 times the MW capacity redirected.

(note: difference in originally proposed example was $9.55/MW-Week, which captured not only the path value difference, but also the term of service value difference)

Redirect Settlement Example 3:
TC1 purchases Yearly Firm service from the TP at a rate of $24,476/MW-Year, which is an equivalent daily rate (on a 7 day/week basis) of $24,476/52/7=$67.24/MW-Day. The TP posts Daily Firm service on a 5 day/week basis. For the original path, this is posted at $24,476/52/5 = $94.13/MW-Day for every day of the year. TC1 submits and confirms a Redirect on a firm basis for April 25, 2005. The Daily Firm rate on the Redirected path is posted at $97.88/MW-Day. The difference in service due on the Redirect would be computed as $97.88/MW-Day less $94.13/MW or $3.75 times the MW capacity redirected.

(note: difference in originally proposed example was $29.89/MW-Week, which captured not only the path value difference, but also the term of service value difference. In this case, MOST of the difference in value is based upon term of service differential, not path differential)

Redirect Settlement Example 4:
TC1 purchases Weekly Firm service from the TP at a rate of $476.1/MW-Week, which is an equivalent daily rate (on a 7 day/week basis) of $476.1/7 = $68.01/MW-Day. The TP posts Daily Firm Service on a 5 day/week basis. For the original path, this is posted at $476.1/5 = $95.22/MW-Day each day of that week. TC1 resells a portion of that service to TC2. TC2 resells a portion of that service to TC 3. TC3 submits and confirms a Redirect on a firm basis for a day. The posted Daily Firm rate on the redirected path is posted at $97.88/MW-Day. The difference in service due on the Redirect would be computed as $97.88/MW-Day less $95.22/MW-Day or $2.66 times the MW capacity redirected. This difference would be charged to TC3; TC1's obligation to the TP remains unchanged.

(note: difference in originally proposed example was $29.87/MW-Week, which captured not only the path value difference, but also the term of service value difference. In this case, MOST of the difference in value is based upon term of service differential, not path differential)

Redirect Settlement Example 5:
TC1 purchases Daily Firm service from the TP at a rate of $97.88/MW-Day. TC1 resells that service to TC2. TC2 submits and confirms a Redirect on a firm basis for that same day to a less expensive path/zone that is posted at a rate of $84.30/MW-Day. The difference in service due on the Redirect would be computed as $84.30/MW-Day less $97.88/MW-Day or a credit of $13.58 times the MW capacity redirected. This difference would be paid to TC2; TC1's obligation to the TP remains unchanged.

NORTH AMERICAN ENERGY STANDARDS BOARD

Executive Committee Meeting – WEQ, REQ, RGQ, WGQ Meeting Materials

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Wholesale Electric Quadrant

TAB 13

Recommendations for Vote – R04006D: OASIS 1A Enhancements - Sale or Assignment of Transmission Service

- Recommendation R04006D is attached. The comment period for this request will end on November 28. No comments have been received to date. If comments are received they will be provided under separate cover.
- To approve the recommendation that would provide an enhancement to OASIS for sale or assignment of transmission service, a motion to accept the recommendation would be made by a WEQ EC member, and the resulting vote would need to be 67% of the WEQ EC members (20 of 29 members) and 40% of each segment's EC members.
- The materials in Tab 13 correspond to agenda item 5 for the WEQ EC agenda.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **Wholesale Electric Quadrant**
Electronic Scheduling Subcommittee
Request No.: **R04006-D**
Request Title: **OASIS 1A Enhancements - Sale or Assignment of Transmission Service**

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

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **Wholesale Electric Quadrant**
Electronic Scheduling Subcommittee
Request No.: **R04006-D**
Request Title: **OASIS 1A Enhancements - Sale or Assignment of Transmission Service**

3. RECOMMENDATION

SUMMARY:

This recommendation establishes standard business practices related to secondary market sales of transmission service. These standards address certain provisions of Section 23 in the FERC Pro Forma Open Access Transmission Tariff titled "Sale or Assignment of Transmission Service."

The Business Practice Standards recommendation is divided into three sections:

- Definitions
- Resales
- Transfers

In reviewing this recommendation, please note the questions posed in Section 4(d) – Commentary/Rationale of Subcommitte(s)/Task Force(s) for specific questions posed by the Subcommittee.

RECOMMENDED STANDARDS:

Definitions–The following definitions shall be added to the Business Practice Standards:

Assignee – An Eligible Customer that receives point-to-point transmission service rights from a Reseller either through a Resale or a Transfer.

Effective Hourly Rate – For Yearly transmission service the effective hourly rate shall be 1/12 of the yearly charge divided by the hours in the billing month. For all other services the effective hourly rate shall be the transmission charge divided by the total hours of the transmission product.

Eligible Customer – as defined in the FERC Pro Forma Open Access Transmission Tariff.

Financially Obligated Transmission Customer (FOTC) – The customer financially obligated to the Transmission Provider for transmission service (i.e., service procured either through direct purchase from the Transmission Provider or through a Transfer of transmission rights).

Resale – The request to convey scheduling rights associated with a reservation for Point-To-Point Transmission Service from a Reseller to an Assignee.

Transfer – Request to convey all rights and obligations associated with a reservation for Point-To-Point Transmission Service from a Reseller to an Assignee.

Definitions–The following existing definitions in the WEQ OASIS Business Practice Standards (WEQ BPS-001-000) shall be modified:

Parent Reservation – an existing, confirmed reservation being modified by a Redirect, ~~Transmission Customer's request to redirect,~~ Transfer~~reassign~~, ~~r~~Resale, etc.

Reseller – The customer that holds Point-To-Point Transmission Service rights and offers those rights for sale on the (secondary) transmission market.~~any Transmission Customer who offers to sell transmission capacity it has purchased.~~

Business Practice Standards for Sale or Assignment of Transmission Service

Standard Y: Resales
Any Transmission Customer (Reseller) shall have the right to offer for sale the scheduling rights associated with the points of delivery and receipt of a unconditional Firm or Non-Firm Point-To-Point Transmission Service reservation (i.e. Parent Reservation). Any Eligible Customer (Assignee) may request to purchase those scheduling rights.

Standard Y.1: Rights Conveyed
The confirmation of a Resale shall convey the rights to schedule Point-To-Point Transmission Service from the Reseller to the Assignee.

Standard Y.1.1 Upon confirmation of a Resale on OASIS, the Reseller shall lose those conveyed scheduling rights for the time frame and in the amount of the Resale.

Standard Y.1.2 If the Transmission Provider (TP) determines the Reseller is not the legitimate owner of the reserved capacity in the Parent Reservation(s), the TP has the right to nullify the Resale.

Standard Y.1.3 The Assignee shall be obligated directly to the TP for all arrangements required for scheduling transactions on the TP's system, including submission of schedules, provision for losses, etc.

Standard Y.1.4 Renewal rights, if any, are not conveyed in a Resale.

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Standard Y.1.5 The Assignee shall have the right to resell rights acquired through a Resale in accordance with these standards subject to Standard Y.7.

Standard Y.1.6 The Assignee shall have the right to Redirect rights acquired through a Resale in accordance with these standards subject to Standard Y.6 and OASIS Business Practice Standards 9 and 10 (Redirects).

Standard Y.2: Financial Obligations
Resales shall not affect the Financially Obligated Transmission Customer's (FOTC) financial obligations to the TP or any other terms of service under the tariff.

Standard Y.3: Service Attributes and Timing
A Resale shall retain all the same transmission service attributes, transmission service priority, and points of delivery and receipt of the Parent Reservation. For example, if one hour of a Monthly Firm reservation is Resold, the Resale reservation shall be a Monthly Firm Resale reservation lasting one hour.

Standard Y.3.1 The TP's OASIS shall not impose any restrictions regarding the timing of a Resale, either submission times or service duration, except that the start and stop times of the Resale must be within the bounds of the Parent Reservation(s) that are designated as supporting the Resale.

Standard Y.3.2 The Reseller shall have the right to aggregate multiple reservations into a single Resale provided that each reservation being aggregated is of exactly the same service attribute, priority, product and point of receipt/point of delivery.

Standard Y.3.3 A Resale must be in whole hours, beginning at the top of the hour, and within the start and stop time(s) of the Parent Reservation(s).

Standard Y.3.4 Service arranged through a Redirect on a non-firm basis (i.e., secondary service) cannot be resold.

Standard Y.4: Quantity
A Resale must be in whole MWs and equal to or less than the Granted Capacity of the Parent Reservation(s), less any reductions (e.g. confirmed Redirects,

previous Resales, curtailments, or implemented schedules) to the capacity available for scheduling of that Parent Reservation.

Standard Y.5: Posting on OASIS
All Resales shall be posted on OASIS.

Standard Y.5.1 A Resale may be arranged between the Assignee and Reseller on OASIS, in accordance with the OASIS Standards and Communication Protocols (S&CP) for "Secondary Sales – On OASIS."

Standard Y.5.2 If the Resale is not conducted on OASIS, the Reseller must notify the TP of the Resale via the OASIS, in accordance with the OASIS S&CP for "Secondary Sales – Off OASIS." This posting should be made as soon as practicable, but in any case prior to the Assignee's exercising of any rights under the Resale.

Standard Y.5.3 The Reseller shall clearly identify on OASIS whether or not the Resale is subject to recall pursuant to Standard Y.7.

Standard Y.6: Redirect of a Resale
The Assignee shall have the right to Redirect firm rights acquired through a Resale. Any such request shall be submitted directly to the TP and will be queued and evaluated in the same manner as any other Redirect. (Subject to any limitations otherwise identified in these standards).

Standard Y.6.1 The Assignee shall be obligated directly to the TP for any charges or credits resulting from any Redirect on a firm basis. The credit or charge shall be assessed per the Redirect Standard.

Standard Y.6.2 Prior to accepting a Redirect request on a firm basis from the Assignee, the TP shall have the right to require that the Assignee execute a Transmission Service Agreement.

Standard Y.7: Reseller Capacity Recall
The Reseller may retain the right to recall capacity from a Resale, in whole or in part, pursuant to this Standard.

Standard Y.7.1 The Reseller shall clearly identify any such provisions to the Assignee.

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Standard Y.7.2 The Assignee shall not remarket, Redirect, or otherwise modify in any form rights subject to being recalled.

Standard Y.7.3 The Reseller and the TP shall have the right to prevent attempts to remarket, Redirect, or otherwise modify in any form rights subject to being recalled.

Standard Y.8 Displacement of a Resale
In the event a Transmission Provider's Tariff requires that a higher priority, competing transmission service request must displace all or a portion of a confirmed lower priority reservation, the TP shall have the right to nullify any Resales that reference the displaced reservation as their Parent. This applies to non-firm service only.

Standard Y.8.1 Resales for firm service are not subject to displacement in accordance with these standards.

Standard Z: Transfers
Subject to the limitations below, a Financially Obligated Transmission Customer (FOTC or Reseller) shall have the right to Transfer all of their rights and obligations under an existing, confirmed Firm or Non-Firm Monthly or Yearly Point-To-Point Transmission Service reservation (i.e. Parent Reservation) to another Transmission Customer (Assignee). Such Transfer may be for all or a portion of the capacity of that reservation. Resales may not be Transferred.

Standard Z.1: Rights Conveyed
The confirmation of a Transfer of transmission rights shall convey all rights and obligations under the Transmission Provider's tariff from the Reseller to the Assignee, including the financial obligation to the TP.

Standard Z.1.1 Prior to the confirmation of a Transfer, the prospective Assignee and TP shall have executed a Transmission Service Agreement.

Standard Z.1.2 The Transfer must be agreed to by the FOTC, the Assignee, and the TP. The conveyance of Transfer rights is not complete until the TP approves the Transfer. The Transmission Provider shall not unduly withhold such approval.

Standard Z.1.3 Upon confirmation of the Transfer on OASIS, the FOTC (Reseller) shall lose those conveyed rights for the time frame and in the amount of the Transfer.

Standard Z.1.4 The Assignee shall be obligated directly to the TP for all arrangements required for scheduling transactions on the TP's system, including submission of schedules, provision for losses, etc.

Standard Z.1.5 If the Transfer is for long-term firm service, renewal rights shall be conveyed from the Reseller to the Assignee on the path and in the amount transferred.

Standard Z.1.6 The Assignee of a Transfer shall have the same rights to Redirect, Resell, Renew, etc. the Transfer as the Reseller previously had with respect to the Parent Reservation being transferred.

Standard Z.2: Financial Obligations
Upon confirmation of the Transfer on OASIS, the Reseller is released from the financial obligation to the TP for the capacity granted over the time period of that Transfer and those financial obligations are conveyed to the Assignee.

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Standard Z.3: Service Attributes and Timing
Transfers shall retain all the same transmission service attributes, transmission service priority, and points of delivery and receipt of the Parent Reservation.

Standard Z.3.1 The start time of the Transfer may occur at any point during the period of service of the Parent Reservation, but must begin at the top of an hour.

Standard Z.3.2 The stop time of the Transfer must coincide with the stop time of the Parent Reservation.

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Standard Z.4: Quantity
A Transfer must be in whole MW's and equal to or less than the capacity of the Parent Reservation subject to the following:

Standard Z.4.1 Partial Transfers in an amount less than the full capacity granted of the Parent Reservation shall be limited to the granted capacity of the Parent Reservation less any reductions (e.g. confirmed Redirects, previous Resales) to the capacity available for scheduling of that Parent Reservation. In other words, only the capacity available for scheduling may be Transferred in a Partial Transfer.

Standard Z.4.2 Full Transfers for the entire capacity granted of the Parent Reservation shall result in the Transfer of all capacity of the Parent Reservation and the Transfer of all encumbrances associated with that capacity in the form of confirmed Redirects, Resales, or any other reductions in reserved capacity.

Standard Z.4.2.1 Full Transfer of a Parent Reservation which has been redirected, in whole or in part, will automatically result in the Transfer of the child(ren) Redirect(s).

Standard Z.4.2.2 Full Transfer of a Parent Reservation which has been resold through a Resale, in whole or in part, will automatically result in the Transfer of the child(ren) Resale(s).

Standard Z.4.2.3 The amount (MW's) of the full Transfer will include capacity which is not available for scheduling due to curtailment or other reduction, if any.

Standard Z.5: Posting on OASIS
All Transfers shall be posted on OASIS.

Standard Z.5.1 Notwithstanding negotiations between the Assignee and the FOTC (Reseller), which may be conducted off OASIS, Transfers must be posted and approved by all parties on OASIS, in accordance with the OASIS S&CP.

Standard Z.5.2 The FOTC (Reseller) shall identify on OASIS those existing transmission service rights that are to be conveyed to the Assignee subject to the review and approval by the TP.

Modification to Redirect Standards

The following modifications should be made to Redirect Standard 9.8.1:

9.8.1 If not addressed in the Transmission Provider's tariff or in a Service Agreement, any difference in charges associated with the Redirect on a Firm basis will be the responsibility of the TC submitting the Redirect. This difference ~~a credit on the Parent Reservation~~ shall be ~~computed~~ calculated as the total MWHs redirected times the difference between the Effective Hourly Rate of the transmission service being redirected and the Effective Hourly Rate of the transmission service that is requested. ~~reservation charge divided by the total megawatt hours reserved times the megawatt hours redirected. The redirected reservation shall be charged as if it were a reservation with a request type of ORIGINAL.~~

Additions to Redirect Standard Examples

The following additions will be included in the Redirect Standard Examples to illustrate the implementation of revised Standard 9.8.1:

Redirect Settlement Example 1:
TC1 purchases Monthly Firm service from the TP at a rate of $2035/MW-Month for the months of February and March of 2005. The Effective Hourly Rate for February is $2035/(28*24) = $3.0283/MW-Hour, and for March is $2035/(31*24) = $2.7352/MW-Hour. TC1 submits and confirms a Redirect on a firm basis for the week of Feb 28 through March 7, 2005, at a rate of $476.10/MW-Week, or an Effective Hourly Rate of $476.10/(7*24) = $2.8339/MW-Hour. The difference in service due on the Redirect would be computed as $2.8339*7*24 = $476.10 for the Redirected service less $3.0283*1*24 + $2.7352*6*24 = $466.55 for the original service, or $9.55 times the MW capacity redirected.

Redirect Settlement Example 2:
TC1 purchases Yearly Firm service from the TP at a rate of ~~1/12 of~~ $24,476/MW-Year. TC1 submits and confirms a Redirect on a firm basis for April 25, 2005 at the rate of $97.88/MW-Day. The Effective Hourly Rate for Yearly service in April is

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$24,476/(12*30*24) = $2.8329/MW-Hour. The Effective Hourly Rate for Daily service on April 25 is $97.88/24 = $4.0783/NW-Hour. The difference in service due on the Redirect would be computed as $4.0783*24 = $97.88 for the Redirected service less $2.8329*24 = $67.99 for the original service, or $29.89 times the MW capacity redirected.

Redirect Settlement Example 3:
TC1 purchases Weekly Firm service from the TP at a rate of $476.10/MW-Week, or an Effective Hourly Rate of $476.10/(7*24) = $2.8339/MW-Hour. TC1 resells a portion of that service to TC2. TC2 resells a portion of that service to TC3. TC3 submits and confirms a Redirect on a firm basis for a day at a rate of $97.88/MW-Day, or an Effective Hourly Rate of $97.88/24 = $4.0783/MW-Hour. The difference in service due on the Redirect would be computed as $4.0783*24 = $97.88 for the Redirected service less $2.8339*24 = $68.01 for the original service, or $29.87 times the MW capacity redirected. This difference would be charged to TC3; TC1's obligation to the TP remains unchanged.

Redirect Settlement Example 4:
TC1 purchases Daily Firm service from the TP at a rate of $97.88/MW-Day, or an Effective Hourly Rate of $97.88/24 = $4.0783/MW-Hour. TC1 resells that service to TC2. TC2 submits and confirms a Redirect on a firm basis for a day for service to a less expensive path/zone at a rate of $84.30/MW-Day, or an Effective Hourly Rate of $84.30/24 = $3.5125/MW-Hour. The difference in service due on the Redirect would be computed as $3.5125*24 = $84.30 for the Redirected service less $4.0783*24 = $97.88 for the original service, or a credit of $13.58 times the MW capacity redirected. This difference would be paid to TC2; TC1's obligation to the TP remains unchanged.

4. SUPPORTING DOCUMENTATION

a. Description of Request:

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.

b. Description of Recommendation:

In considering the request to clarify/standardize treatment of REDIRECT requests for transmission service acquired on the secondary market, the OASIS 1A Task Force determined that a more fundamental set of business practices should be specified dealing with the secondary transmission market. This issue has been discussed in the past in both the NERC Market Interface Committee (MIC) and the Electronic Scheduling Collaborative. The recommended standards presented here are in line with the discussions in those groups in that there are basically two major classes of secondary market transactions that must be recognized: 1) transfer of scheduling rights with no change in financial responsibility, and 2) transfer of all rights, including financial responsibility. Implementation of the second class of secondary market transaction (i.e., TRANSFER in the recommended standard), will require modifications to the OASIS S&CP and corresponding changes in OASIS software.

Standards Y.6 and Z.6 specifically address the issue of Redirects for secondary market transactions.

Standards Y.5.2 and Z.5.3 identify who is ultimately responsible for notification of the TP of the Resale or Transfer respectively. Note that in the case of Resales, the (re)seller documents off-OASIS sales since there is no incentive for that TC to give away rights to another TC without compensation and don't want to give the Assignee rights to "steal" rights from a TC by fraudulent use of the OASIS transassign template. In the case of Transfers, the Original TC could attempt to "dump" financial obligation on another entity without their approval if they could use the OASIS transassign template. Therefore, a TRANSFER request should be initiated by the Assignee taking on the financial burden and won't be allowed to use transassign template, unless we make explicit restrictions in transassign that the Original TC's submission with request type of TRANSFER is to have an implied status of ACCEPTED (as opposed to CONFIRMED for resales).

In support of the Recommendation Sale or Assignment of Transmission Service to the NAESB Executive Committee for a proposed business practice standard, please see the following sets of NAESB subcommittee minutes:

WEQ OASIS 1A Task Force	February 13, 2004	http://www.naesb.org/pdf/weq_oasis1a_021304dm.pdf
WEQ ESS/ ITS	April 6, 2004	http://www.naesb.org/pdf/weq_ess_its040604fm.doc
WEQ ESS/ ITS	May 26-27, 2004	http://www.naesb.org/pdf/weq_ess_its052604dm.doc
WEQ ESS/ITS	February 17-18, 2004	http://www.naesb.org/pdf/weq_ess021704fm.doc
WEQ OASIS 1A	July 14, 2004	http://www.naesb.org/pdf/weq_oasis1a_071404fm.doc

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: Wholesale Electric Quadrant
Electronic Scheduling Subcommittee
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Task Force		
WEQ ESS/ITS	September 29-30, 2004	http://www.naesb.org/pdf/weq_ess_its092904fm.doc
WEQ OASIS 1A Task Force	November 1, 2004	http://www.naesb.org/pdf2/weq_oasis1a_110104fm.doc
WEQ OASIS 1A Task Force	November 5, 2004	http://www.naesb.org/pdf/weq_oasis1a_110504fm.doc
WEQ ESS/ITS	November 18-19, 2004	http://www.naesb.org/pdf/weq_ess_its111804fm.doc
WEQ ESS/ITS	January 12-13, 2005	http://www.naesb.org/pdf2/weq_ess_its011205fm.doc
WEQ OASIS 1A Task Force	February 4, 2005	http://www.naesb.org/pdf2/weq_oasis1a_020405fm.doc
WEQ OASIS 1A Task Force	February 15, 2005	http://www.naesb.org/pdf2/weq_oasis1a_021505fm.doc
WEQ OASIS 1A Task Force	February 28, 2005	http://www.naesb.org/pdf2/weq_oasis1a_022805fm.doc
WEQ OASIS 1A Task Force	March 14, 2005	http://www.naesb.org/pdf2/weq_oasis1a_031405fm.doc
WEQ OASIS 1A Task Force	April 4, 2005	http://www.naesb.org/pdf2/weq_oasis1a_040405fm.doc
WEQ OASIS 1A Task Force	April 15, 2005	http://www.naesb.org/pdf2/weq_oasis1a_041505fm.doc
WEQ OASIS 1A Task Force	April 22, 2005	http://www.naesb.org/pdf2/weq_oasis1a_042205fm.doc
WEQ ESS/ITS	May 11-12, 2005	http://www.naesb.org/pdf2/weq_ess_its051105fm.doc
WEQ ESS/ITS	July 13-14, 2005	http://www.naesb.org/pdf2/weq_ess_its071305fm.doc
WEQ ESS/ITS	August 31-September 1, 2005	http://www.naesb.org/pdf2/weq_ess_its083105dm.doc
WEQ OASIS 1A Task Force	October 18, 2005	http://www.naesb.org/pdf2/weq_oasis_1a_101805dm.doc
WEQ ESS/ITS	October 20-21, 2005	
WEQ ESS/ITS	October 27, 2005	

c. Business Purpose:

The Business Practices will provide market participants with procedures for providing any necessary data for the secondary market sales of transmission service. These

standards address certain provisions of Section 23 in the FERC Pro Forma Open Access Transmission Tariff related to the "Sale or Assignment of Transmission Service."

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

The following are specific areas where the Task Force would like to receive comment and feedback on the proposed standard, and provides information on why the proposed standard was drafted as it was.

- **Resale of firm service has been limited to "unconditional" service. The first aspect that led to this restriction is "customer protection". That is, when purchasing firm service on the secondary market, the Assignee TC will be assured, with this restriction in place, that their service is locked. The second aspect is that the complexity of un-winding a chain of resales and potential redirects of a "conditional" service reservation may be significant. The TP and/or OASIS would have to be able to correctly annul/displace all subordinate resales/redirects that may have been entered into. This inserts the TP in the middle of third-party agreements. Is the cost/benefit to the potential secondary market for firm service to add the complexities and potential liabilities of handling Resales of "conditional" firm service justified?**
- **The granting of redirect rights to a Resale of firm service was debated extensively. Proponents indicated that it makes firm rights offered on the secondary market more attractive. Opponents cite that resale is "scheduling rights only" but Redirect on Firm basis is "treated as a new request". Does this mean the Redirect of a Resale has (or should have) different standing than Redirect of a firm reservation held by the same party? The biggest problem in this area was the settlements issue. The original/current Redirect standard gave a full credit on the original path and a full obligation on the new path. As long as these are the same entity, this presents no problem. If applied to Resales, however, the original "FOTC" basically would no longer owe the TP, and the Resale TC would all of the sudden have full obligation to the TP. But, that TC also has a "side-deal" payment to the Reseller TC that resold their rights. If this Redirect standard is kept in place, the third-party TC needs to seek relief from whoever they purchased the Resale rights from to compensate for their new obligation to the TP. The Task Force opted to change this to make the third-party TC to only be obligated to TP for any difference in charges related to the Redirect. Commenters should consider the following questions in their comments to this aspect of the proposed standard:**
  - **i. Should Resold firm capacity have the ability to redirect on a firm basis?**
  - **ii. If yes, how should the TP recover any differences in transmission costs related to the service resold vs., the service on the redirected path (i.e., handling of zonal rates, and/or path discounting)?**
- **Resale (and Transfer) reservations MUST retain the original service attributes and priorities of service being resold. The Task Force debated this and agreed that the "reseller" should not have the ability to "change" the fundamental**

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Request No.: R04006-D
Request Title: OASIS 1A Enhancements - Sale or Assignment of Transmission Service

nature of the rights they hold when those rights are resold on the secondary market. Current practices may allow a TC holding monthly firm rights to remarket those rights as weekly firm, daily firm, daily non-firm, etc. But, from the TPs perspective, if the original rights holder schedules service, those schedules are treated as monthly firm schedules whether scheduled next week or next hour. If the TC is allowed to remarket those rights under various other TP offered "services", the Assignee is being treated differently by the TP when it is time to schedule or curtail service than if those same rights were being used by the original holder. The Task Force felt this was giving the Reseller the right to change the fundamental nature of the rights they were reselling and that was not something that should be allowed. The result is that if a TC purchases Monthly firm service directly from the TP, they should not be allowed to change the nature of those rights when being resold to other TCs. The only way to preserve the TPs treatment of those original rights was to require that the Resale rights retained all the original attributes and priority of the rights being resold. This means that TP OASIS systems must allow a Resale of Monthly Firm service for the term of even a single hour to insure that the Assignee's use of the scheduling rights purchased on the secondary market are treated comparably to the original TCs rights purchased directly from the TP. Comments on this aspect of the standard are requested.

- **The Task Force included extending the right for the Reseller to "recall" rights sold on the secondary market under specified circumstances. There is a similar type of provision in the NAESB Gas Capacity Release standards. By allowing Resales to have the ability to Redirect on different paths, there is a potential that the original rights resold are long gone when the Reseller elects to exercise their "recall" option. For this reason, the Task Force made the restriction that if a TC wants to have the rights to recall at their option, the Assignee cannot remarket those rights to others or redirect to alternate paths. Comments are requested on:**
  - **i. Should the right for "recallability" of Resales even be part of the standard?**
  - **ii. If so, is the restriction that Assignee may not remarket that capacity appropriate since it is subject to recall beyond their control?**
- **The concept behind "Transfer" was primarily to handle cases where one entity might buyout the entire portfolio of another, or in cases or mergers/divestitures, or other significant business events. It was not envisioned to be a common/routine business transaction. As such, the Task Force thought it resonable to limit the services eligible for transfer to the more long term (i.e., Monthly and Yearly) services. Is this a reasonable restriction?**
- **Transfers envisioned for mergers, etc., are limited to basically the "balance of service" from an arbitrary start time but limited to end on the exact same stop time as the service being transferred. Is such a limitation reasonable? If not, commenters must clearly indicate how one might determine the disposition of "rollover" rights if the middle years of a multi-year long term contract were**

transferred to a new owner. Do all rollover rights stay with the TC owning the rights at the ultimate end of the original term? Does the TC getting the intervening years have any rollover rights for that service in addition to the original holder's rollover rights?

- **The Task Force debated what should be done if the original rights being transferred had been sliced and diced on the secondary market or redirected. The result was that if the original is tranfered in toto (portfolio buyout or merger/divestiture) that all the "children" encumberences move to the new holder to collect on, etc. If, however, the transfer is only in part, the part that can be transferred is limited to only those rights held "free and clear" by the Reseller, i.e., they can't dump rights resold by others. This restriction is due to the potentially complex nature of specifying just exactly which MWs and at what times are being given to the Assignee and the complexity of electronically tracking this information. Comments regarding this restriction for "full" vs. "partial" transfers are solicited.**
- **Resales are currently allowed "off-OASIS" as long as the final nature of the resale is posted for the TP by the Reseller. Justification is that the Reseller is losing rights so they have no incentive to mis-represent Resales. Transfers require a three-way confirmation between Reseller, Assignee and TP. The Task Force debated that Transfer could be posted by the Assignee, since the Assignee is taking on a financial obligation to the TP and there would be no incentive for the Assignee to submit fraudulant information. However, the Assignee could mis-enter those rights held by the Reseller and "take" rights that the Reseller had no intention of releasing. For this reason, it was felt that the Reseller should have an electronic means to "approve" the transfer information supplied by the Assignee. The TP always should have the ability to "nullify" a deal that doesn't meet their requirements. For these reasons, the Task Force felt that Transfer, basically, must be conducted on OASIS with electronic approvals by the three parties, TP, Reseller, and Assignee. The OASIS S&CP needs to reflect this new functionality. Comments are requested on whether Resales "Off-OASIS" should be eliminated, or at least have the S&CP standards require that even though entered by the Reseller to document the Resale, the Assignee should still have some electronic "confirmation" process to show and document that they agree with the counter-party's representation of the transaction.**

WEQ ESS/ITS 10/27/05

The following motion was made at the October 27, 2005 WEQ ESS/ITS Conference call:

To send Recommendation R04006D to the Executive Committee for adoption.

The vote was unanimous with five participants attending.

NORTH AMERICAN ENERGY STANDARDS BOARD

Executive Committee Meeting – WEQ, REQ, RGQ, WGQ Meeting Materials

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Wholesale Electric Quadrant

TAB 14

FERC Filings and Comments

- This material is for review only. No action is needed. The document provided is a report, docketed in RM05-5-000, on November 16 regarding the Commission's request that NAESB renumber its WEQ standards.
- The material in tab 14 corresponds to agenda item 8 of the WEQ agenda.

NORTH AMERICAN ENERGY STANDARDS BOARD
1301 Fannin, Suite 2350 • Houston, Texas 77002 • **Phone:** (713) 356-0060 • **Fax:** (713) 356-0067
email: naesb@naesb.org • **Web Site Address:** www.naesb.org

November 16, 2005
Filed Electronically

The Honorable Magalie Salas
Secretary
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, D.C. 20585

RE: Report for NAESB Wholesale Electric Business Practices, Docket No. RM05-5-000, Renumbering of Standards

Dear Ms Salas:

The North American Energy Standards Board ("NAESB") provides this notification to the Federal Energy Regulatory Commission ("FERC" or "Commission") regarding NAESB's activities undertaken to renumber wholesale electric quadrant business practice standards for ease of reference and to ensure the uniqueness of the number. The text of the standards and the order in which they are presented has not changed.

This effort was undertaken at the request of FERC staff, and applies to all wholesale electric business practices standards: namely, the standards submitted in the January 18, 2005 "Report for NAESB Wholesale Electric Business Practices", Docket No. RM05-5-000[1]; and further noted in the April 18, 2005 "Supplemental Report for NAESB Wholesale Electric Business Practices", Docket No. RM05-5-000; and the July 1, 2005 "NAESB Comments on Docket No. RM05-5-000 'Standards for Business Practices and Communication Protocols for Public Utilities.'" The FERC also proposed to amend its regulations to incorporate by reference certain of these standards in the May 9, 2005 FERC Notice of Proposed Rulemaking Docket No. RM05-5-000.

Please note that we are filing this report electronically in Adobe Acrobat® Print Document Format (.pdf). All of the documents are also available on the NAESB web site (www.naesb.org). Please feel free to call me at (713) 356-0060 or refer to the NAESB website should you have any questions or need additional information regarding this report.

Respectfully submitted,

Rae McQuade
President and COO, North American Energy Standards Board

cc: Mr. M. Rosenberg, Federal Energy Regulatory Commission
Mr. M. Goldenberg, Federal Energy Regulatory Commission
Ms. K. Morice, Federal Energy Regulatory Commission
Mr. M. Maassel, NAESB Chairman and CEO
Mr. William P. Boswell, NAESB General Counsel
Mr. M. Desselle, NAESB Vice Chairman (WEQ)
Mr. L. Oberski, NAESB Executive Committee Chairman for the Wholesale Electric Quadrant

[1] The standards may be downloaded from the NAESB web site at no cost for members and non-members who may choose to purchase Home Page Access. The standards can be ordered from NAESB for those without home page access for a minimal fee. The fee covers all modifications made to the purchased version. To purchase the WEQ standards, the NAESB Materials Order form should be completed and forwarded to the NAESB office. The form can be downloaded from the NAESB web site at http://www.naesb.org/pdf/ordrform.pdf.