Consideration of Comments

Project 2008-12 Coordinate Interchange Standards

The Project 2008-12 drafting team thanks all commenters who submitted comments on the appropriate disposition of requirements in the current approved INT standards that were identified by stakeholders as candidates for consideration under criteria developed by the Paragraph 81 drafting team. The proposed draft INT standards, a mapping document showing the proposed disposition of requirements from the current approved standards as well as a summary of the proposed revisions, a list of comments received on the INT standards during Phase 1 of Paragraph 81, and the additional supporting documents were posted July 25, 2013 through August 23, 2013. Stakeholders were asked to provide input through a special electronic comment form. There were 29 responses, including comments from approximately 100 different people from approximately 68 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Russel Mountjoy	MRO NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayliegh Wilkerson	Lincoln Electric System	MRO	1, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madision Gas and Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	Midcontinent Independent System Operator	MRO	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Scott Bos	Muscatine Power and Water`	MRO	1, 3, 5, 6
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Edleman	Nebraska Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Brian Shanahan	National Grid	NPCC	1
23.	Wayne Sipperly	New York Power Authority	NPCC	5
24.	Donald Weaver	New Brunswick System Operator	NPCC	2

25.	Ben Wu	Orange and Rockland Utilities	NPCC	1
26.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Sammy Roberts	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Skiba	MISO	SERC	2
2.	Daniel Hawk	LG&E/KU	SERC	1, 3, 5, 6
3.	Wayne Van Liere	LG&E/KU	SERC	1, 3, 5, 6
4.	Bob Thomas	IMEA	SERC	4
5.	William Berry	OMU	SERC	3
6.	James Case	Entergy	SERC	1, 3, 6
7.	Robert Scott Homberg	TVA	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporaton	RFC	1
2.	Annette Bannon	PPL Susquehanna, LLC	RFC	5
3.		PPL Montana, LLC	WECC	5
4.		PPL Generation, LLC	RFC	5
5.	Elizabeth Davis	PPL EnergyPlus, LLC	NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6
10.			MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Randi Heise	NERC Compliance Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	Dominion	RFC	5, 6
2.	Louis Slade	Dominion	SERC	1, 3, 5, 6
3.	MIke Garton	Dominion	NPCC	5, 6
4.	Randi Heise	Dominion	MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Sasa Maljukan	Hydro One Networks Inc.	X		X							

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1, 3

				1	2	3	4	5	6	7	8	9	10
7.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

				1	2	3	4	5	6	7	8	9	10
8.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
2.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
3.	Dave Millam	Kansas City Power & Light	SPP	1, 3, 5, 6
4.	Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
5.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
6.	Susan Quinn	Westar Energy	SPP	1, 3, 5, 6
7.	Buck Reuter	Westar Energy	SPP	1, 3, 5, 6
8.	Marc Welsh	Westar Energy	SPP	1, 3, 5, 6
9.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
9.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Suzie Stone	Trans Commercial System Mgmt	WECC	1
2.	Wes Hutchison	Trans Commercial System Mgmt	WECC	1
3.	Mary Willey	Trans Commercial System Mgmt	WECC	1

				1	2	3	4	5	6	7	8	9	10
10.	Individual	Kelly Cumiskey	PacifiCorp	X		X		X	X				
11.	Individual	Pamela Hunter	Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	X		X		X	X				
12.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
13.	Individual	Raj Hundal	Powerex						X				
14.	Individual	Nazra Gladu	Manitoba Hydro	X				X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Individual	Shari Heino	Brazos Electric Power Coop	X				X					
16.	Individual	Ed Skiba	MISO		X								
17.	Individual	Michael Falvo	Independent Electricity System Operator		X								
18.	Individual	Chris Nebrigich	Idaho Power Co.										
19.	Individual	Michael Lowman	Duke Energy	X		X		X	X				
20.	Individual	John Bee	Exelon and its' Affiliates	X		X		X					
21.	Individual	Kathleen Goodman	ISO New England Inc.		X								
22.	Individual	Michelle R. D'Antuono	Occidental Power Services Inc.			X							
23.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
24.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
25.	Individual	Bob Thomas, and Alice Schum	Illinois Municipal Electric Agency				X						
26.	Individual	Richard Vine	California Independent System Operator		X								
27.	Individual	Oliver Burke	Entergy Services, Inc.	X									
28.	Individual	Silvia P. Mitchell	NextEra Energy	X		X		X	X				
29.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
Xcel Energy	MISO
Hydro One Networks Inc.	NPCC RSC
South Carolina Electric and Gas	SERC OC Review Group
Illinois Municipal Electric Agency	SERC OC Review Group, and MISO
Brazos Electric Power Coop	ACES
ISO New England Inc.	we agree with NPCC RSC members comments and offer additional input as well.

1. **Paragraph 81 Considerations: The Coordinate Interchange SDT (CISDT) has reviewed all of the previously posted INT standards, along with stakeholder feedback on the INT standards from Phase 1 of the Paragraph 81 project, as well as outstanding FERC directives assigned to the Coordinate Interchange project. The CISDT believes that all of the requirements remaining in the four standards that are being posted are necessary and require accountability. Please review the mapping document and the list of Paragraph 81 recommendations provided to the INT team as a result of comments received from stakeholders during Phase 1 of Paragraph 81, along with the proposed revisions to the INT standards. If you believe that a specific requirement in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard, please provide the specific standard and requirement number, along with a specific suggestion for an alternate means to ensure the intended action is accomplished. Some examples of alternate means could include working with NAESB to incorporate the requirement into NAESB business practice standards; moving the requirement into the Guideline and Technical Basis section of the same standard; or working with a technical committee to develop a NERC guideline. Please be as specific as possible.**

Summary Consideration: The Coordinate Interchange Standard Drafting Team posted drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1 for a 30-day public comment period from July 25 – August 23, 2013. The posting was designed to gather stakeholder feedback regarding the proposed requirements, especially with respect to Paragraph 81 criteria and the recommendations made in the Independent Expert Review of the NERC standards. The drafting team carefully reviewed all comments submitted during the comment period, along with previous Paragraph 81 comments[2] and Independent Expert Review recommendations[3], but there was not clear stakeholder consensus on which standards or requirements should be retired. Therefore, the drafting team considered each of the recommendations and comments and incorporated those that team found to improve the quality of the standards. Specifically, the team revised many

[2] The Consideration of Comments document for Project 2013-02 Paragraph 81's August 3-September 4, 2012 comment period can be downloaded at http://www.nerc.com/pa/Stand/Project%20201302%20Paragraph%2081%20DL/Comment_Report_P81_090412_final_responses_for_posting.pdf.

[3] The Standards Independent Experts Review Project - Final Report can be downloaded at http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf, along with the Standards Independent Experts Review Project - Requirements Scoring Spreadsheet at http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_IERP_Requirements_Spreadsheet_August_29_2013.xls.

requirements and removed four requirements that were previously posted, largely consistent with the recommendations made in the Paragraph 81 comments and the Independent Expert Review.

INT-004

- R1: An exception for Pseudo-ties that are already accounted for in congestion management tools was added and the detail on the MW amount to be included on the transaction was eliminated.
- R2: The requirement was revised to apply to only those LSEs that submitted and RFI per R1. The drafting team also simplified the language or R2.1 and R2.2 and R2.3.
- R3: This was removed as an interim registration process was determined to be unnecessary.
- R4: The requirement was modified to require entities to register Pseudo-Ties when the registration process is available in the NAESB Electric Industry Registry (EIR).
- The drafting team added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard.

INT-006

- R1: This requirement was removed. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation.
- R2, R3: The drafting team revised the language for clarity.
- R4: The drafting team added the specific entities to perform the review.
- R5: No changes. These requirements direct that 'active' approval is required to transition to Confirmed Interchange; that if entities do not approve the transaction that it will not be transitions to Confirmed. If the software were not automatically performing this function, this requirement identifies the logic to be applied.
- R6: No changes. This distribution requirement may currently drive how software performs this function. However, if that software were not present this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.
- Tables: The drafting team removed columns A and C details as these are no addressed in any requirement. These details remain in the NAESB timing tables.

INT-009

- R1: The drafting team added phrase "by a Reliability Coordinator" to clarify what aspect of INT-010 is applicable to this requirement.
- R2: No change was made to language but language was added to the Rationale.
- R3: This requirement was unchanged and was not removed as suggested by some commenters. Since the Transmission Operator is not a part of the approval process for the Interchange, this requirement is the only means by which they are aware of the need to adjust the HVDC flow.

INT-010

- R1: This language was modified to be consistent with the currently effective requirement. This results in minimal revision to the existing, enforceable requirement.
- R2, R3: The drafting team revised the term "created" to "submitted".
- R4: The drafting team agreed with comments that these are rules for when reliability adjusts should be used and if reliability adjusts were issued for reasons other than this it would not impact reliability. We agree these would be included in the NAESB business and the requirement is removed from the standard.
- R5: The entities to receive the transaction for evaluation are included today in the eTag specification, Section 3.6.1.1.1 so the drafting team has removed this requirement.
- R6: Pseudo-ties were added to the requirement and the language was clarified.
- The drafting team added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard.

Several entities from the ERCOT area requested exemption from some or all of the standards. When the drafting team reviewed the requirements we did not see that an exemption is required. For example, on INT-011, if ERCOT does not have point-to-point service, the requirement would not apply and an exemption is not needed. However, when we look at INT-006, if ERCOT is involved in a transaction outside its area, all of these requirements would apply.

Organization	Question 1 Comment
ACES Standards Collaborators	(1) In general, most of the requirements in the INT standards either are business practices or steps that occur in tagging software that do little if anything to support reliability and there are only a few basic things that need to occur with Interchange to support reliability. First, tagging dynamic schedules and pseudo ties and intra-BA transactions are commercial equity issues intended to ensure these transactions are curtailed equitably with other transmission service. RC, BAs and TOP can always re-dispatch (which is essentially all a transmission service curtailment is) in other ways. The whole purpose of the IDC and WECC USF is to ensure transmission service is curtailed equitably and in an organized fashion. If commercial equity was not an issue these tools would not exist. Second, many of the requirements dealing with distributing Arranged and Confirmed Interchange are in fact software tool application and not necessary. Third, the adjacent BAs must agree to a common interchange number with equal value but opposite sign. This would include ensuring that dynamic transfers are accounted for correctly in either scheduled interchange or actual interchange and utilizing a common meter point. Technically, the interchange could even be wrong as long as both BAs are controlling to the same number but opposite in sign which avoids frequency deviation. While we would agree it is advantageous to build the interchange values from individual interchange schedules, from a reliability point of view, it is not necessary. However, these steps really boil down to accounting for each transaction, the ownership, energy imbalance, and various sundry of other commercial equity concerns. Thus, each schedule essentially represents a business transaction and is accounted for separately to facility business processing and making it easier to identify errors in interchange. Second, the BAs must ensure that they can support the magnitude of the Interchange including the ramping capability. Third, the transmission system must be able to support the transaction. However, from a practical perspective, the only check that is performed here is to ensure that a valid transmission service reservation is utilized and not overrun. Failing to allow Arranged Interchange that utilizes a perfectly valid transmission

Organization	Question 1 Comment
	service reservation to proceed to Confirmed and Implemented Interchange could be viewed as a tariff violation unless there is an imminent transmission threat (i.e. violated IROL). The Arranged Interchange could be utilizing a higher priority transmission service reservation that will bump other Implemented Interchange that utilizes lower priority transmission service. In essence, the request is submitted to re-allocate transmission service to the highest priority through tools such as the IDC. Thus, most TSPs are reluctant to not allow Arranged Interchange to transition to Confirmed Interchange due to transmission constraints.(2) We disagree with requiring Dynamic Schedules and Pseudo-Ties to be tagged in a reliability standard (INT-004-3). The purpose of tagging these schedules is a commercial equity issue. By NERC definition (both proposed and existing), a Dynamic Schedule is already correctly implemented in both the Attaining and Native Balancing Authorities. Thus, load, generation, and interchange will be balanced. Thus, the only reliability concern that is left is if the transmission system can handle the Dynamic Schedule. Since the vast majority of these Dynamic Schedules are grandfathered and, those, that are not will utilize firm transmission, the transmission system can certainly handle these Dynamic Schedules. This means that the only issue left is that it is a commercial equity and transparency issue. Because it has been historically recognized that these transactions will be accommodated on the transmission system in all but the rarest cases, years ago, market participants recognized that if these transaction were not tagged and firm transmission was curtailed, these transaction would not receive any curtailment. At that time, market participants held seats on NERC groups such as the Operating Reliability Subcommittee and insisted on these transactions being tagged for fairness. This means it is a business practice and rightfully belongs in a NAESB standard. Even the purpose statement of the standard is clear that the purpose is to ensure that the transactions are accounted for in congestion management procedures appropriately. This is not a reliability concern and it should be transitioned to a NAESB business practice.(3) Congestion management procedures (such as the IDC and WECC USF) cannot be viewed as primarily reliability tools and, thus, tagging transactions is essentially a commercial equity issue to ensure fair and non-discriminatory transmission service. Rather these tools are implemented to help ensure an orderly prioritization of transmission service. They help ensure that only those transactions with a

Organization	Question 1 Comment
	significant impact are curtailed on a flowgate or transfer path and that the lowest priority transmission service is curtailed first. They also help to reallocate flows when higher priority transmission is scheduled on an already congested flowgate or transfer path. FERC has held in Order No. 693 that congestion management tools such as the IDC in essence are not reliability tools by refusing to allow them to be the only tool used to unload a flowgate experiencing an IROL exceedance. IRO-006 reflects this. NERC's CEO recently supported this position at the August 2013 NERC BOT meeting in Montreal when he stated the reason NERC no longer supports the IDC is because it is a congestion management tool and not a reliability tool. We strongly recommend the review team eliminate all non-reliability concepts from the INT standards.(4) INT-004-3 - The reliability impact of Dynamic Schedules will be addressed appropriately in the agreement established between the Attaining and Native BAs. The agreement will include items such as common metering points, implementation dates, testing requirements, etc. No additional reliability standards requirements are necessary for Dynamic Schedules. A NERC reliability guideline might be appropriate to identify what should be in these agreements and how to implement a Dynamic Schedule successfully.(5) Only the definition for Dynamic Schedule is proposed to be modified. Dynamic Interchange Schedule is also defined the same as Dynamic Schedule. If the drafting team is proposing to eliminate Dynamic Interchange Schedule this should be stated clearly or it should also be included in the definition. If it will be retired, all standards should be reviewed to ensure it is not use elsewhere. (6) INT-004-3 R2 - The "is reviewed" should be modified in the standard. The checks that must occur to move Arranged Interchange to Confirmed Interchange could be viewed as a review. Thus, we suggest that the wording should state more directly what is required. The energy profile is to be compared against the actual energy flow. (7) INT-004-3 Part 2.3 - This could be stated more simply. If the RC or TOP instructs the LSE to update the tag, they should. (8) INT-004-3 R3 - This is clearly a business practice as stated in the rationale box and implementation plan. The requirement is expected to be implemented in a NAESB standard. This makes it clear this is a business practice and we cannot support this as reliability standard requirement enforceable by sanctions. (9) INT-004-3 - Part 3.2 implies that a BA can have more than one reliability coordinator. We do not believe this is possible from a practical

Organization	Question 1 Comment
	perspective. Please clarify that a BA has one and only one RC and adjust Part 3.2 accordingly. (10) INT-004-3 - R4 - This requirement is clearly a business practice and should be removed. Any requirement that directs a registered entity to comply with a NAESB business practice will in essence be a business practice itself. While it may be desirable for many reasons to comply with a NAESB business practice, it simply does not rise to the level of reliability requirement. If it did, then the Pseudo-Tie registry should be moved to NERC.(11) INT-004-3 - Native and Attaining BAs are used in the Guidelines and Technical Basis section. They should be included with this standard as a result. (12) INT-006-4 R1 - This requirement does not reflect the practical reality with how E-tags are generated and approved. It is this practical reality that obviates the need for the requirement. Any entity such as a PSE or LSE must have tagging software to create E-tags. In turn, BAs and TSPs have tagging software that they use to review and approve the E-Tags. When an LSE or PSE enters a request for interchange as an E-tag, that E-tag is essentially communicated to all entities that need to approve the E-tag at the same time. These software packages have become so entrenched, it would be impossible for a BA, TSP, LSE or PSE to enter into an interchange transaction or to review approve one without the software. Thus, the need for the requirement to have the Sink BA distribute the Arranged Interchange has been obviated with the entrenchment of the software.(13) INT-006 R1 - This requirement is not necessary because an interchange transaction is essentially business transaction. The only reliability component to the transaction is for the sending and receiving BAs to ensure they have equal but opposite interchange values and it is really only necessary to ensure this for the Composite Interchange Schedule and not each individual interchange schedule.(14) INT-006-4 Part 2.2 - Denying Arranged Interchange or curtailing Confirmed Interchange because the scheduling path is invalid is a business practice issue. While we agree that this is a necessary task to comply with open access transmission tariffs, it is not a reliability issue but rather a business practice issue. Furthermore, this is a validation that should be performed automatically with tagging software. Thus, this part should be removed. (15) INT-006-4 Part 3.1 - Denying Arranged Interchange because the transmission path is invalid is a business practice issue and is not a reliability issue. It provides no indication for whether the transmission system can handle the Arranged Interchange. This should be moved to a NAESB

Organization	Question 1 Comment
	business practice. Furthermore, this is something that should be automatically handled via the tagging software and is obviated by the entrenched nature of the software. (16) INT-006-4 R5 - While we agree the timing tables provide an orderly structure for processing requests for interchange, Arranged Interchange and Confirmed Interchange, the simple reality is that the timing tables in Attachment 1 are a business practice and present the opportunity for zero-defect enforcement contrary to the reliability assurance initiative. Whether the sink BA distributes the Arranged interchange within one minute of receiving it is immaterial to reliability. If the sink BA takes two minutes to process Arranged Interchange and there is still ample time for all approvals to be given how is reliability harmed? If a BA and TSP take longer to perform their "reliability assessments" than the time allotted but the Arranged Interchange proceeds to Confirmed and then Implemented Interchange, how is reliability harmed? Some entities can literally process thousands of the Arranged Interchanges per month. Because no computer system can be expected to work perfectly all the time (consider that six sigma established maximum reliability levels at 99.99966% and most tagging software probably does not achieve this idealized reliability rate) , it is a guarantee that some Arranged Interchange will not be processed according to the timing tables for some Arranged Interchange. Thus, these timing tables should be moved to NAESB business practices. The binary nature of the VSLs continue to use the zero-defect compliance approach and should be modified as well. For each of the thousands of schedules that occur on the Interconnection each month, there is an opportunity for compliance violations due to the zero-defect approach to compliance. How does this support reliability?(17) INT-006-4 R6 - This part states that the Sink BA must distribute notifications of whether Arranged Interchange was transitioned to Confirmed Interchange per the timing tables. While we agree this approach is a structured and orderly way to process Arranged Interchange and communicate approvals and denials, it is again a business practice. Business practices should be moved to NAESB. Furthermore, the need for the requirement is obviated by entrenched tagging software that is necessary to implement Interchange.(18) INT-006-4 Part 6.4 - PSE has been replaced in many parts of the proposed modifications to the INT standards with LSE. Part 6.4 compels notification of approvals and denials to the PSE but there is no companion part to compel notification to the LSE. Is this

Organization	Question 1 Comment
	intended? (19) INT-006-4 - Guideline and Technical Basis - The first main bullet on page 18 states that the LSE “that approves or denies Arranged Interchange”. The LSE does neither. The LSE submits a Request for Interchange that becomes Arranged Interchange once the appropriate reliability entities receive and approve the request. (20) INT-006-4 - Guideline and Technical Basis - The first sub-bullet under the second main bullet on page 18 refers to communication that occurs between BAs, TSPs and PSEs. This is not consistent with the remainder of the proposal which focuses on replacing PSEs with LSEs. (21) INT-009-2 R1 - Because this requirement references another standard, it creates the opportunity for double jeopardy and is vague and ambiguous. The requirement compels a BA to agree with its Adjacent BAs on Composite Confirmed Interchange “as directed per INT-010-2”. Either this requirement should stand alone or INT-010-2 should stand alone. They should not reference one another because any time INT-010-2 is violated, this requirement may likely be violated causing double jeopardy. The reference to INT-010-2 is vague as well. What specifically is directed in INT-010-2 that must be complied with in order to comply with INT-009-2 R1?(22) INT-009-2 R1 - This requirement is redundant with BAL-006-2 R4 which already requires Adjacent BAs to operate to a “common Net Interchange Schedule and Actual Net Interchange value” with opposite signs. Redundancy is one of the paragraph 81 criteria. Please remove the redundancy to avoid implementing requirements that will be retired later. (23) Request for Interchange definition - This definition uses the term Interchange inconsistent with the NERC definition. It states that a Request for Interchange may be a “bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority”. By NERC definition, Interchange is “Energy transfers that cross Balancing Authority boundaries”. Obviously, a Request for Interchange within a single Balancing Authority does not cross BA boundaries. (24) INT-010-2 R1 - There is an extraneous comma at the end of the requirement. (25) INT-010-2 R2 - We are not convinced this requirement is needed. The E-Tag specification already includes specific details about the Reliability Level associated with an E-Tag and how a reliability entity may in essence cap the energy flow at this level. Why is a separate NERC requirement needed? (26) INT-010-2 R1 and R3 - Because the practical reality is that Interchange cannot be implemented without utilizing tagging software, we question the need

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	for these two requirements. Ensuring the interchange transactions are tagged essentially has become a business practice. (27) INT-010-2 R4 - Part 4.1 through Part 4.5 should be written as bullets and not numbered lists. Per a NERC filing to FERC, NERC has stated that numbered lists are utilized when each element of the list must be met while bullets are utilized when they are options and not everyone needs to be met. The lists seem to meet the latter more accurately. (28) INT-010-2 R6 - Requirement R6 uses the wrong term Reliability Adjusted Arranged Interchange. Reliability Adjusted Arranged Interchanged is a request and not confirmed or implemented and, thus, could be denied. Until confirmed and implemented, the BA should not control to this value.(29) INT-010-2 R6 - Requirement R6 potentially conflicts with IRO-006-EAST-1 R4. R4 allows alternate actions to be implemented rather than schedule reductions particularly if the schedule reductions will not be effective. INT-010-2 R6 seems to presume that congestion management tools such as the IDC and USF are surgically accurate and requires curtailments of Dynamic Schedules to be implemented as specified. The tools do have some inaccuracies and can result in curtailments that do not alleviate flows at times. Thus, R4 should allow alternate action such as re-dispatch similar to IRO-006-EAST-1 R4. (30) INT-011-1 does not support reliability and is simply a commercial equity issue and business practice. RCs, BAs, and TOPs are perfectly capable of working together to require a BA to re-dispatch its system without tagging these intra-BA transactions. In fact, FERC recognized that congestion management tools such as the IDC are not really reliability tools and required NERC to reflect this in the standards. IRO-006-EAST-1 R1 requires the RC to actually implement another action such as re-dispatch besides TLR to mitigate IROL exceedances. Thus, one can only conclude that standard is intended to ensure that congestion management procedures such as the IDC include these intra-BA transactions for commercial equity purposes. Even the purpose statement of the standard seems to reflect this in the statement intra-BA transfers utilizing Point-to-Point transmission service "are communicated and accounted for in congestion management procedures". Thus, the purpose is ultimately a commercial equity issue to account for these transactions. Furthermore, the fact that it focuses on Point to Point transmission service shows that is a FERC tariff issue which is clearly about curtailing transmission service based on its priority. Tariff issues by definition are commercial equity and

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	business issues. Please strike this entire standard.(31) Intermediate Balancing Authority - We disagree with the proposed definition. The proposed definition removes the requirement that this BA must be on the scheduling path. Please provide technical justification for why a BA not on the scheduling path would be considered an Intermediate BA. (32) Definitions - Please provide a technical justification for the need for the proposed changes to existing definition and a complete review of their use in the NERC standards. We need absolute clarity that modifying these existing definitions will not impact the meaning of other standard negatively. Until this is completed, we cannot support these proposed changes. (33) Composite Confirmed Interchange - Based on the use of Composite Confirmed Interchange in INT-009-2 R1, we believe that this is intended to be the Interchange in aggregate between two BAs and not a single BAs net interchange. Please clarify the definition accordingly. Otherwise, the definition could be interpreted to be Net Scheduled Interchange for a single BA. (34) We believe the proposed modification to the definition of OPA is unnecessary. The definition includes expected generation output levels. How could expected generation output levels not include the impact of Interchange? It is included implicitly. (35) Paragraph 81 Comment Review - The matrix of comments regarding paragraph 81 project comments appears to be missing a significant number of comments. It would appear only six commenters commented on retiring INT standards per paragraph 81. This seems too low. (36) Thank you for the opportunity to comment.
Manitoba Hydro	(5) INT-006-4, Application Guidelines - for consistency with other sections of the document, remove all the ‘periods’ from the end of the bullets listed in this guideline. (6) INT-009-2 - for consistency with the other INT standards, remove the ‘periods’ from the end of the bullets listed in this section. (7) INT-010-2 - for consistency with the other INT standards, remove all ‘periods’ from the end of all bullets listed in this standard. (8) INT-010-2, R1 - remove the comma at the end of R1. (10) INT-011-1 - add a period following the definition of Interchange Coordination. (11) INT-011-1, R1.1 - periods are inconsistently being utilized throughout this standard. Manitoba Hydro suggests adding or removing the period(s) from the end of all

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	sentences. (12) General Comment - replace “Board of Trustees” with “Board of Trustees’” throughout the applicable documents/standards for consistency with other standards. (13) INT-006-4, R4 - for reliability reasons the Reliability Coordinator would identify the curtailment and the best resolution from the big picture. If a BA denies the transaction the burden is shifted to the neighbors. Is there a better mechanism or language to resolve this problem? How do you police it? (14) Manitoba Hydro is in agreement with the language in INT-006-4, R5 & R6, but believes that clarity is needed in the Attachment 1 - Timing Table. How does a transaction start 1 hour after the start time?
Powerex	1. Paragraph 81 Considerations: The Coordinate Interchange SDT (CISDT) has reviewed all of the previously posted INT standards, along with stakeholder feedback on the INT standards from Phase 1 of the Paragraph 81 project, as well as outstanding FERC directives assigned to the Coordinate Interchange project. The CISDT believes that all of the requirements remaining in the four standards that are being posted are necessary and require accountability. Please review the mapping document and the list of Paragraph 81 recommendations provided to the INT team as a result of comments received from stakeholders during Phase 1 of Paragraph 81, along with the proposed revisions to the INT standards. If you believe that a specific requirement in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard, please provide the specific standard and requirement number, along with a specific suggestion for an alternate means to ensure the intended action is accomplished. Some examples of alternate means could include working with NAESB to incorporate the requirement into NAESB business practice standards; moving the requirement into the Guideline and Technical Basis section of the same standard; or working with a technical committee to develop a NERC guideline. Please be as specific as possible. Comments on INT StandardsPowerex would like to thank the CISDT for their hard work in developing a more consolidated and concise version of the Interchange Standards, and respectfully submits the following comments for consideration.General Comments:Powerex has reviewed the latest draft of the Interchange Standards and considers

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	these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing inaccurate information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations.Powerex believes that it is fundamentally important that all interchange be scheduled using e-Tags, and appropriately evaluated by the reliability entities listed on the e-Tag. Ensuring that all interchange transaction are e-Tagged allows reliability tools, such as NERC IDC and WECC webSAS, to effectively manage congestion through curtailment based on transmission priority. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. Definitions: 1) The phrases "reliability events" or "reliability assessment" are not defined and are key concepts in these new standards. In INT-010-2 the language was changed to allow exemptions where reliability entities can modify or initiate schedules under abnormal Operating conditions. Now it allows those changes or new schedules to "address reliability events". Powerex believes that these terms should be defined to remove any ambiguity within these standards. 2) The definition of Intermediate BA has been modified, but it is not clear as to why a new definition is required or why the old definition is inadequate? Further rationale on the changes in definitions would be useful for the industry in evaluating these standards.3) INT - 009 creates two new definitions for Attaining BA and Native BA. Is there a need to create these new definitions or could we use the currently defined NERC terms such as Sink or Receiving BA, and Source or Sending BA? Further rationale is required as to the reasons for the new definitions, and reasons for not using the current NERC definitions.4) INT - 009 modifies the definition of Confirmed Interchange. However, the definition only requires Sink BA to verify Arranged Interchange, but it should also state that the Sink BA has also verified that interchange has been approved by all BAs and TSP listed on the e-Tag.INT - 004 - Dynamic Transfer1) R1 as currently written is only

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	applicable to LSEs that use Dynamic Transfer to serve load, and is not applicable to any PSE that submits a Dynamic Transfer. Powerex believes that the standard should be applied to all entities that use Dynamic Transfers, whether it is used to serve load or provide imbalance service. The Dynamic Transfer, regardless of its intended use, has the same level of impact to the BES, and applying this requirement only to subset of all Dynamic Transfers would not meet the intent and purpose of this standard. 2) R1, the second bullet, we would suggest removing the word "expected". It is counter-intuitive to suggest that we use the "expected maximum" in the situation where there is "no forecast". Powerex prefers that the requirements be clear and the removal of "expected" would provide that clarity. 3) The standard is silent on the transmission requirements that would be used for the Dynamic Transfer. It is important that the transmission capacity required to support the transfer of dynamic flow be appropriately obtained, validated and verified prior to implementation. For example, dynamic schedules that are e-Tagged at an average MW level, but do not have sufficient transmission capacity above the average MW level may cause SOL exceedances when dynamic dispatches exceed the average MW indicated on the e-Tag. These types of scheduling issues result in cascading curtailments, which has impacts to other Generators and Loads that must accommodate as a result of the inaccurate scheduling of Dynamic Transfers. It is important that this standard clearly articulate that each dynamic transfer shall procure sufficient transmission to accommodate the maximum dynamic transfer. INT - 006 - Evaluation of Interchange1) There does not appear to be any requirement that prescribes at a minimum that an Interchange Transaction or Interchange Schedule must be submitted for energy that flows between Balancing Authorities. This should be the case and a new requirement should be developed to reflect this. Otherwise some entities may choose not to submit certain interchange transactions even though it may affect adjacent Balancing Authorities and TSPs.2) This standard must prescribe at a minimum the verification and validations that must be performed during the reliability assessment by a BA and TSP. Those minimum requirements should not be prescribed in the Technical Guidance section of the standard because they would not be considered mandatory and could be ignored by Responsible Entities. It is imperative that this standard provide clear requirements that ensure BA and TSP are validating impacts, and not

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	allowing transactions to flow that will cause issues within the interconnection. For example, a Source BA should validate and not allow a generator to schedule above and beyond its nameplate capacity to ensure accurate scheduling. Powerex believes that a Source BA will only perform these types of checks if there is a prescribed minimum requirement within a standard, and suggests that the CISDT provide the minimum set of validations. 3) A BA or TSP should deny an interchange that does not accurately provide information especially in relation to the possible BA generation and load. Eg. A generator scheduling 200 MW from a 100 MW nameplate should be actively monitored, verified and denied by BA and VRF/VSF should be established to ensure that BA administers that check. In addition to that BAs should also evaluate and determine if the interchange supports an actual load, and the exports from a Source BA do not exceed generation located in the BA. 4) R2 and R3 does not hold the BA or TSP accountable to correctly approve or deny the interchange request the first time, and allows the entities to rectify the issue through curtailment of the interchange. Powerex believes that these requirements should be modified to rectify a possible loophole that could lead to inefficient scheduling practices.5) M2 and M3 should measure the times the BA or TSP approves a request without proper verification or validation and then subsequently curtails the interchange once they realize the mistake. The BA or TSP should perform a thorough validation of an Arranged Interchange to avoid such instances which rectify BA or TSP mistakes. Powerex suggests that when a BA or TSP reevaluates a Confirmed Interchange that they note in the comments the reason for the reevaluation. 6) For Attachment 1, there should be a reference point for the time that constitutes whether or not an Arranged Interchange is “on-time” or not. The previous Standard (INT-006-3) used to have the second column of the Timing Requirements table labeled as “IA Assigned Time Classification”. The new table heading for the second column is not assigned to an entity and states just “Time Classification”. This will result in potential disputes as to who determines and classifies whether or not the RFI is “on-time”. An Entity should be assigned the responsibility to determine the correct time classification (On-Time, Late, etc). Powerex suggests that the Sink BA be the Responsible Entity, and that once the Sink BA assigns a classification that other approval entities should respect that classification.INT - 010 - Modification of Interchange1) In R1, the term “energy sharing” is not

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	capitalized and thus is open to interpretation, and this leaves the door open for entities to submit RFIs after the scheduling deadlines. In the original INT-010-1, this issue was dealt with by describing the circumstance which this was allowed, specifically "...a loss of resources covered by an energy sharing agreement....". Either "energy sharing" needs to be defined, or the conditions to allow these modifications should be limited. Powerex suggests reverting back to the current INT-010-1 language use, "...a loss of resources covered by an energy sharing agreement....".2) R4.5 states that "Any real-time reliability concern" could lead to a Reliability Adjustment. Powerex believes that this requirement requires further clarification. Could the CISDT provide examples of other reliability concerns outside of R4.1 to R4.4 that would qualify for R4.5? Powerex is not aware of any other reliability concerns than the ones listed for R4.1 to R4.4, and suggests that R4.5 be modified to be more specific by providing details regarding the bounds or that R4.5 be removed entirely.3) R6 should also apply to Pseudo Ties and not just Dynamic Schedules. Powerex suggests that the language be revised to include Pseudo Ties or that a separate requirement be drafted to limit Pseudo Tie transfers when reliability limits are placed on the interchange.
City of Austin dba Austin Energy	Austin Energy (AE) requests that the SDT review the applicability of these standards in the ERCOT Region. Because ERCOT ISO is the only Balancing Authority in the ERCOT Interconnection, Dynamic Interchange from or to another Balancing Authority does not occur in the ERCOT Interconnection. AE requests the SDT make the applicability clear in the Applicability section using an approach similar to the MOD A project. Example text would be: 4.3 Exemptions: The following is exempt from INT-004-3. 4.3.1 Functional Entities operating in the ERCOT Region. AE believes this exemption is appropriate for all the INT standards in this posting, including the newly proposed INT-011-1.
Bonneville Power Administration	BPA supports NERC's decision to retire INT-001-3; INT-003-3; INT-005-3; INT-007-1 and INT-008-3 and NERC's proposed changes in the following Standards INT-009-2; INT-010-2 and INT-

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	011-1. BPA has comments and concerns regarding the two INT standards below. INT-004-3; Dynamic TransferDefinitions of Terms Used in StandardBPA suggests adding proposed new definitions in this section: Attaining Balancing Authority and Native Balancing Authority. Purpose Statement BPA agrees with the Purpose statement change. However, the Purpose statement is not updated in the INT-004-3 draft as identified in the Summary of Revisions (e.g., “tool” rather than “procedures” plus the cited examples).BackgroundIn 1st bullet - R1 does not originate from INT-004-2, but rather from INT-001-3. R2 should not be referenced in this 1st bullet. BPA suggests the 1st bullet to read, “R1 is modified from INT-001-3 to incorporate requirements....”In 2nd bullet - BPA suggests the 2nd bullet to read, “R2 is modified from INT-004-2 to separate....”Requirements and MeasuresWill the text boxes for R2 and R3 be moved to the Application Guidelines section of the Standard INT-004-3, when it has received its ballot approval? BPA supports R3 and R4 additions. When this Standard becomes final, BPA suggests the “effective statements” found in the Rationale boxes be retained within the Standard. Application Guidelines”Table 1” reference in last paragraph (on page 11) has no “Table 1” labeled in the document. Either label the subsequent table “Table 1” or just reference “table below”. INT-006-4; Evaluation of Interchange Transactions1) This INT standard states that rather than the Interchange Authority Service, the Sink BA is now responsible for sending the approval request to all Approval Entities applicable to the Arranged Interchange. The Sink BA is also responsible for collecting and compiling all approval responses and communicating the final state back out to the entities involved. In the west, these communication actions are currently conducted via WIT. Would this proposed INT result in any system or protocol changes in the west or would WIT still be used as it is today to provide these communications on behalf of the Sink BA? 2) BPA would like the drafting team to clarify the change made to timing tables that are applicable to WECC. The current NAESB timing tables have column "B" titled "The GPS, LSE, and PSE Conduct Market Assessment" however the timing table presented in INT-006 changes the title of the column to "BA and TSP Conduct Reliability Assessments". Our concern is that the timing tables appear to no longer be applicable to the Market Operators; GPS, LSE, or PSE's. As one of these entities, we exercise our review and approval rights on e-Tags each day. BPA believe that it is both helpful and

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	appropriate for the timing tables to detail the amount of review time not only for BA's and TSP's but for GPE, LSE, and PSE's. We would request that the drafting team review the timing table and determine if another change to the column heading is appropriate or if the addition of a new column addressing the timing assessments for GPE, LSE, and PSE will resolve our concerns. Thank you for the opportunity to comment.
Duke Energy	Duke Energy submits the following comments:INT-004The elimination of PSE in the Applicability Section of this standard and the associated requirements moves away from the NERC Functional Model. Duke Energy suggests a slight modification to R1, “ Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted by the PSE as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie at either:”Duke Energy believes that R3.2 should only include the RC. If a different Registered Entity is required, this issue should be addressed by a Regional Reliability Standard. INT-006 Duke Energy suggests replacing “Balancing Authority Area” with “Balancing Authority” for the definition of Adjacent Balancing Authority.Duke Energy would like for the SDT to consider adding a provision to R6 when scheduling systems are down, a move to a back-up control center, etc. These types of events could create a compliance risk with Attachment 1, Column D. Duke Energy also seeks clarification on the term “reliability assessments”. Who is responsible for conducting these “reliability assessments”? Per the functional model, TSPs do not conduct these types of assessments. Is it the intent of the SDT for the TSP to conduct a reliability assessment prior to approval of an Arranged Interchange? INT-009Duke Energy suggests changing the language in R1.2 to read, “Agree to the direction of the Composite Interchange with Adjacent Balancing Authority.”
Exelon and its' Affiliates	Exelon agrees with the rationale for INT-004 R3 and R4, but feels that they but fall short of a requirement for the BA or NAESB to periodically (annually at minimum) communicate the list of

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	Pseudo Tie lines within their zone to each Distribution Provider (DP) / Electric Distribution Company (EDC). Additionally, DPs/EDCs with no pseudo-ties in their zone should likewise be informed as well.Exelon would like to see the requirements address dynamic load that switches from LSE to LSE or from LSE to the Provider of Last Resort (POLR). The requirements should also address the situation of creating dynamic schedules for load at aggregate nodes. Exelon would like to see the order of the requirements in INT-004 changed from: R1, R2, R3, R4 to R3, R4, R1, R2 because we feel that proper registration of a Pseudo Tie Line must occur in order for requirements one and two to be effective. Finally, Exelon feels that there should be an exception to Violation Severity Levels for R1 and R2 in the situation where the Pseudo Tie Line was not properly registered by the BA in R3 and/or R4.INT-009-2 includes new definitions for Dynamic Schedule and Pseudo-Tie requiring that these values be treated as Interchange Schedules and Actual Interchange, respectively, and included in ACE equations. It is confusing, then, that R1 should specify that Composite Confirmed Interchange is to be calculated without inclusion of Dynamic Schedules and Pseudo-Ties. As Dynamic Transfers represent inputs to the ACE equation, and measurements against which a BA is managing its balancing function, to exclude them from the Composite Confirmed Interchange seems to paint an inaccurate picture of the Interchange between two Balancing Authorities. If the intention is to not skew Composite Arranged Interchange by the inclusion of values that change in Real Time with no settled value available until after-the-fact, that can be easily accomplished by stipulating that estimated values of Dynamic Schedules and Pseudo-Ties not be included in Composite Confirmed Interchange, and that the real-time values should be used for calculation of Composite Confirmed Interchange in the Real Time horizon, with the agreed on after the fact values used for calculation of Composite Confirmed Interchange in the after the fact horizon.
Northeast Power Coordinating Council	In general, these Standards represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in NAESB Business Practice Standards, which are the sources of the software specifications, and open to the industry for comment and voting, that would be adequate to serve reliability needs. Comments

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	by each individual Standard:INT-004For those entities that utilize dynamic transfers the transparency that the requirements provide is necessary for reliability.INT-006Requirements R1 and R6 can be removed (assuming the Standard is not retired) because they deal with given concepts of Arranged Interchange. INT-009BAL-005 Requirements R9 through R12 could be revised to incorporate the language/intent of these INT requirements. INT-009 would no longer be necessary. Regarding INT-009 R3, even though this requirement has been present since the original policy language was converted to Standards, it is an obvious function that is required in order for the flow to be set as desired. INT-010Requirements R1 through R3 are administrative to “document” the flow after the fact. This is good practice. These Requirements would be more appropriate in another Standard, possibly INT-011-1 Interchange Coordination Support. R4 is simply trying to enforce that entities don’t use the “expedited” approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 has reliability value in that an expedited process to have a curtailment approved is desirable. However, a RC can direct people to do something without the Tag. It is definitely needed in the software design to ensure the typical process of a curtailment is efficient. R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule. If someone gets a Tag curtailment, that is their notice to adjust the source generation. They should not have to wait to get that direction (again) from somewhere else.
NERC Compliance Policy	In reviewing the INT standards associated with this Project, it would be helpful to have all impacting changes to the document redlined for review. Dominion suggests the SDT adopt the best practices of denoting the status of all changes rather requiring the reader to deduce the status from a range of statuses requiring additional research. For example, INT-011.1 includes a newly defined term identified as “This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.” Underlining added for emphasis.Dominion would like to state that in addition to INT-004-3, the revised definitions, “Dynamic Schedule” and “Pseudo-Tie” are also associated with reliability standards BAL-2-WECC-2 - Contingency Reserve, BAL-003-0.1b -

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	Emergency Response and Bias and BAL-005-0.2b - Automatic Generation Control, as noted in the Definitions of Terms Used in Standard section. Dominion believes that future instances of any change to a standard should be provided to the balloting body as red-line documents and noted for ease of modification identification and review. Dominion questions whether the word 'desires' in Requirement 1 should be replaced with 'is required'? We doubt that a PSE would desire to submit Requests for Interchange if it isn't required to do so. Dominion commends the SDT for concise mapping of the current requirements in the standards to the revised or relocated requirements.
Western Electricity Coordinating Council	INT-004-3, R2: Sub requirements should not have requirements under it. seems like 2.1.1 and 2.2.1 can be deleted because R2 already says that the updates should be made for future hours.INT-004-3, R3 and R4: Rationale for R3 says it will be effective until NAESB registry accepts Pseudo-Tie registrations. Rationale for R4 says it will become effective once the NAESB registry accepts Pseudo Tie registrations. Nothing in the standard under implementation/effective date indicates that R3 and R4 will not be effective at the same time. Suggestion would be to remove R3 and move the implementation date to once NAESB registry accepts pseudo tie registration. As written, it appears that R3 and R4 will be effective at the same time.INT-006-4, R1: Reference to other requirements in 1.1 makes it confusing. R1 appears to have two requirements. Consider splitting into two separate requirements.INT-006-4, R2: Reference to another requirement makes the language confusing.
Idaho Power Co.	INT-004-3: In R1 I have some concerns with the requirement to submit dynamic/pseudo schedules at the expected maximum MW profile if no forecast is available. Seems like this could create some confusion on what is considered a forecast. The transmisison is typically set at maximum and energy set at expected. Not sure if we need an option specifying what to tag if there is no forecast. I don't believe that R3 or R4 provide any reliability benefits to the Bulk Electric System. These Requirements could be addressed in another document. Also, I noticed

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	that several comments have stated that the industry should consider retiring all INT Standards and moving some if the requirements that impact reliability to the BAL Standards. I feel that there is value in retaining the INT Standards and not integrating them into the BAL Standards.
PPL NERC Registered Affiliates	INT-004-3The PPL NERC Registered Affiliates recommend removing language concerning Pseudo Ties from this Standard. It appears the R1 and R2 are attempting to require real-time hourly tags for Pseudo Tied loads. These Requirements would necessitate adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and existing reliable processes. The existing functionally in the IDC provides greater visibility, accountability, and more accurate data - all contributing to increased reliability. Also, Balancing Authorities are already aware of the effects of Pseudo Ties upon their systems because such effects are accounted for in their ACE equations. It is unclear what the technical justification is for requiring Pseudo Tied loads served by DNRs via NITS to use the Arranged Interchange process outlined in this Standard.Furthermore, we agree and support the SERC OC and MISO comments relating to tagging of Pseudo Ties in INT-004-3.
California Independent System Operator	INT-006At a minimum, R1 and R6 are the best candidates for removal, though all of INT-006 could be removed.To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the industry for comment and voting, that would be adequate. INT-009BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of these requirements. Thus, this Standard would no longer be necessary. When specifically reviewing R3, although this requirement has been present since

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	the original policy language was converted to standards; it is an obvious function that is required in order for the flow to be set as desired. This is comparable to generators needing to be told where to operate but there is no requirement for 'who' to notify them. INT-010R1-R3 are administrative to 'document' the flow after-the-fact. Real Time has already passed so it is not necessary for reliability. It is good practice to do these activities but they should be documented in best practices outside of the requirements.R4 is simply trying to enforce that entities don't use the 'expedited' approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 may have some reliability value in that we desire an expedited process to have a curtailment approved. R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule. If someone gets a Tag curtailment - that is their notice to adjust the source generation. INT-011INT-011 R.1 is needed to address the FERC directive identified in Order 693 (see Paragraph 817). Additionally, this directive was not one of the directives FERC suggested to withdraw in Notice of Proposed Rulemaking RM13-8-000 issued June 20, 2013.
Occidental Power Services Inc.	INT-011-1, Applicability Section and R1. The market structure and market operations of ERCOT renders R1 inapplicable. There is only one Balancing Authority within ERCOT (ERCOT itself) and, therefore, no intra-Balancing Authority Interchange. There is interchange across the DC ties between ERCOT and the Western and Eastern Interconnections, but this standard only applies to "intra-Balancing Authority areas." The Applicability Section should be revised to say "4.1.1. Load Serving Entities, except those in ERCOT."
NextEra Energy	NextEra Energy (including Florida Power & Light Company (FPL)) is registered for all functions, except Reliability Coordinator (RC), and FPL is the RC agent for the Florida Reliability Coordinating Council (FRCC). As such, NextEra has considerable experience with interchange, and, based on this experience it finds that all the Interchange Standards should be retired. There are a number of reasons that NextEra has come to this conclusion. One, all the

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	Interchange Standards meet the P81 criteria, including there is no reliability gap resulting from the retirement of the INT Standards. Second, NAESB already is regulating interchange via the e-tag system. Third, the independent expert's report supports the elimination of the Interchange Standards. Fourth, the few FERC outstanding directives issued on Interchange are outdated, and, therefore, should not impact the retirement of the Interchange Standards. In short, NextEra strongly recommends that the next posting of the INT Standards be focused on retiring all of the INT Standards.Interchange Standards meet the P81 criteria.The P81 criteria requires that both Criteria A and B be met to indicate that a Reliability Standard is appropriate to be retired.Criterion A of P81 states:The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "... operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."Interchange Standards do little to promote reliable operation, because: (i) as the independent expert report indicates all the interchange specifications are set forth in NAESB's e-tagging specifications and as well (ii) there is no correlation between the Interchange Standards and "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system" do not occur. For those few aspects of Interchange Standards that are designed to ensure interchange is included in real-time monitoring and operations as well as situational awareness, these aspects are already covered in BAL-001, BAL-002, BAL-004, BAL-005, BAL-006, EOP-001, EOP-002, IRO-005, IRO-006, TOP-002, TOP-005. There are also WECC-specific interchange Standards and it is addressed in various MOD and TPL Standards. The INT Standards have become outdated, redundant administrative requirements that do little, if anything, to promote reliability. Thus, the Interchange Standards also meet Criteria B1 (administrative in nature), B3 (purely documentation), B6 (commercial or business practice) and B7 (redundant with other

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	requirements and NAESB). The current paradigm of Standards drafting, as set forth in the P81 criteria, as well and the independent expert's decision-trees, requires that the drafting team closely scrutinize the need for the INT Standards. NextEra views the INT Standards as providing no value and addressing no reliability gap. Accordingly, given the current approach to drafting Reliability Standards, the INT Standards should be retired as soon as possible. NextEra could go through each requirement and apply the above criteria, but for SMEs in this area, the application of the P81 criteria should be fairly straightforward. NextEra will send an SME to the next drafting team meeting to help the team focus on retiring requirements. Also, while the drafting team may believe it must have Standards to comply with certain Commission directives, these directives are outdated and with some education we believe the Commission will understand that interchange is more than sufficiently regulated via other Reliability Standards and NAESB.
PacifiCorp	PacifiCorp agrees that the proposed revisions should be addressed within the INT standards; however, there are several areas where the revisions are too broadly constructed and introduce a level of ambiguity that would make compliance with the INT standards challenging. PacifiCorp's concerns are highlighted below: o INT-004-3 R1 and R2: PacifiCorp does not believe there is a reliability benefit to the BES of requiring a Request for Interchange to be submitted as an on-time Arranged Interchange to the Sink Balancing Authority for a Pseudo-Tie. Pseudo-Tie tags do not calculate into any portion of the ACE and are used purely for accounting purposes. o INT-004-3 R3.2: PacifiCorp contends that for a BA's associated RC or TOP to confirm that "sufficient information" to reliably manage the Pseudo-Tie has been provided, it must first be clear what constitutes a "sufficient" amount of information. This language is too broad and subject to interpretation and is therefore difficult to measure. o INT-006-4 R2.2: PacifiCorp suggests the SDT change Balancing Authority to Intermediate Balancing Authority in order to clarify who is to complete the denial or curtailment. The Source and Sink Balancing Authorities are already required to perform this action under R2.1. o INT-006-4 R3.1: PacifiCorp suggests that that SDT expand the description of the "transmission path" to describe

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	other criteria beyond “proper connectivity of adjacent TSPs” such as sufficient OASIS rights, energy profile, physical path, and transmission profile. o INT-006-4 R4: PacifiCorp is uncertain of the reliability benefit of the Balancing Authority communicating a denial to the Reliability Coordinator after the fact and seeks justification from the drafting team. A denial reason is required on the e-Tag which should serve as proper notification. o INT-009-2: o R1: PacifiCorp seeks further clarification of the defined term, “Composite Confirmed Interchange.” Specifically with respect to how Composite Confirmed Interchange differs from Net Scheduled Interchange.o R2: PacifiCorp believes that this requirement is redundant to BAL-005-0.2b R12.1. o INT-010-2 R6: PacifiCorp believes the term “agreed upon values” should be amended to provide more clarity. PacifiCorp requests the SDT specify the method expected to be implemented in order to determine “agreed upon values” used by each BA to ensure limits are not exceeded. Specifically, PacifiCorp wonders if the agreed upon value is the value provided by the Reliability Adjustment Arranged Interchange or if the agreed upon value is based on a verbal communication.PacifiCorp supports the development of new draft Standard INT-011-1. This will support reliability of the BES because creation of the path using Point to Point Transmission Service indicates congestion is possible on that path and management of the path is needed to avoid leaning on other parallel paths.
Entergy Services, Inc.	Please consider utilizing existing functionality through the ownership factors in the IDC to document real time flows and impacts to Pseudo Ties. The concern is the compliance risk and administrative overhead to adjust these tags on an hourly basis.INT-004-3The Title of this standard has been modified from “Dynamic Interchange Transaction ModificationsÂ´ to “Dynamic Transfers”. Entergy recommends that it should be “Dynamic and Pseudo-Tie Interchange Transactions” to reflect inclusion of Dynamic Schedules and Pseudo-Ties.Effective Date: Since certain requirements, as written in this standard, are dependent on NAESB action to modify Electric Industry Registry, the effective date should reflect this dependency.R1 - “on time” included in this requirement is not defined in this standard. Timing requirements that were included in INT-005-3 are now included in INT-006-4. Entergy suggest that either “on-

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	time" referred to in this requirement specifically point to INT-006-4 Attachment 1 or this term be removed from this requirement. Similar reference in M-1 should be adjusted accordingly. There is no need to include the expected maximum MW profile. If the entity can come up with the maximum MW profile, it can also come up with the expected average MW profile. There is no benefit or reliability impact of knowing maximum MW profile. Entergy recommends not including the second bullet for maximum MW profile in the standard.R2 - The language in this requirement is odd. ...ensure the Confirmed Interchange...is reviewed and updated if needed for the next available..... This language is loose and it does not appear like a Standard requirement language. This is modification of the existing requirement that used a threshold of 10% or 25 MW for updating the profile. However, the new language by including the term "if needed" makes it vague. This requires comparing the actual integrated energy for an hour to be compared with the average energy profile for the next hour. The average energy profile for the next hour may actually be required to be more than 10% or more than 25 MW different from the previous hour. There is also not enough time for adjustment of the energy profile for the next hour as the actual integrated energy for an hour cannot be determined till after completion of that hour. Even though this requirement was already in INT-004-2, Entergy recommends to remove this requirement as it does not serve any reliability purpose, is just administrative burden, and difficult to implement.R-3 and R4 - These requirements are administrative and commercial in nature as these require to verify how losses will be accounted for and that sufficient (vague) information to reliably manage the Pseudo-Tie has been provided. These require verifying if these Pseudo-Ties are registered in the NAESB Electric Industry Registry, which capability does not even exist currently. These requirements do not have any reliability impact. Entergy recommends that these requirements should not be included in the reliability standards. Pseudo-Tie Tags will require adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and internal processes. The existing functionally in the IDC (if made a requirement) will provide greater visibility, accountability, and more accurate data - all contributing to increased reliability. The approval and coordination of Pseudo Ties prior to implementation is addressed in R3 & R4 and should be adequate to

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	provide the necessary visibility and awareness between all impacted Bas, TSP, and RCs.Please clarify Requirement 3.3.2. Each of the Balancing Authority's associated Reliability Coordinators (in the Eastern Interconnect) or associated Transmission Operators (in the Western Interconnection) has confirmed that sufficient information to reliably manage the Pseudo-Tie has been provided.INT-006-4The term "Reliability Adjustment Arranged Interchange" is not consistent with other NERC standards and the recommendation is to use "curtailment request".R1 - Reference to " so that these entities can conduct a reliability assessment of the Arranged Interchange before Arranged Interchange is implemented" is unnecessary in this requirement. Requirements for assessments are detailed in other requirements. Entergy recommends removing this reference/phrase.Attachment I, Column A specifies initial distribution of all Arranged Interchanges in less than or equal to one minute of its receipt. Description given in this requirement is very confusing. The phrase in second/last sentence "exceeding the times specified in Attachment 1, Column A..." tends to imply that the distribution can occur in more than one minute. The intent of this requirement needs to be clarified and language modified accordingly. R-2 - Foot note 2 is redundant. Since there is no requirement to provide response to any other requests, the foot note does not add any value. R3 - Foot note 3 is redundant. Since there is no requirement to provide response to any other requests, the foot note does not add any value. Though the note in Rationale for this requirement indicates that TSP may deny for other reasons, R3.1 limits the denial only if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. Since Rationale is not part of the standard Entergy recommends including "other reasons" included in the requirement. TSP can deny if there are not enough scheduling rights (MW available on TSR).R6 - The language of the requirement is odd. Entergy suggests the language to be changed to: Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities such that on-time Confirmed Interchange can be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D:Interchange Authority - Since Interchange Authority is being replaced by the Sink Balancing Authority in these standards, definition of Interchange Authority is not needed any

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	more. SDT should recommend deletion of the definition of Interchange Authority from NERC Glossary.Attachment 1, Column C is not referenced in any Standard. It does not seem to have meaning? It was earlier referenced in INT-008-3 R1 that has been moved to INT-006-3 R6 and reworded. Entergy recommends reviewing this and modifying the language of R6, if needed.INT-009-2These following two terms (Attaining Balancing Authority and Native Balancing Authority) are different than other standards and customary terminology used in the industry. To avoid potential confusion or error it is recommended that “Source BA and Sink BA” be utilized.Attaining Balancing Authority: A Balancing Authority bringing generation or load into itseffective control boundaries through a dynamic transfer from the Native Balancing Authority.Native Balancing Authority: A Balancing Authority from which a portion of its physicallyinterconnected generation and/or load is transferred from its effective control boundaries to theAttaining Balancing Authority through a dynamic transfer.INT-010R1 - What is the reason of using the term “created” in place of originally used term “submitted” in existing standard? The Request for Interchange needs to be submitted and not only created, therefore Entergy recommends keeping the term “submitted”.R2 - Same remark as R1 for the term “created”.R3 - Same remark as R1 for the term “created”.R5 - Use of the term “only to the Source Balancing Authority for reliability assessment tends to imply that if got distributed to any other entity, it is a violation. Entergy recommends removing the term “only” in this requirement. The term “Reliability Adjustment Arranged Interchange” is not consistent with other NERC standards and the recommendation is to use “curtailment request”. The SDT is requested to clarify the term “energy sharing” used in R1: Each Sink Balancing Authority shall ensure that a Request for Interchange is created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement The term “Reliability Adjustment Arranged Interchange” is used throughout the standard. We recommend changing and use “curtailment request”.NAESB Business Practice Standards - There is a concern among the group on how the NERC Reliability Standards will remain in lock-step with the NAESB Business Practice Standards. Has there been an agreement reached on a process to use?INT-011This standard has been developed in response to the FERC

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	directive. This will also facilitate Parallel Flow Visualization (PFV) project that NAESB is working on. In case this standard does not get included in the final NERC standards, this will adversely impact the NAESB effort. Entergy supports this standard.
Brazos Electric Power Coop	Please make it clear that these standards will not apply in ERCOT.
MISO	Tagging of Pseudo-Ties (INT-004 and INT-009)We do not agree that Pseudo-Ties need to be tagged for the following reasons:1. The asset generator defines the reliability impact, and the allocation (tagging discussion) only deals with allocation of energy, which is a business practice. 2. When a unit is pseudo-tied, a new tie line is created between two entities. These new tie lines are subject to compliance with BAL-001, Requirement R1 and BAL-005-0.2, Requirements R12 - R13. These requirements already implement hourly checks of tie line data. This data provides inputs to the Net Actual Interchange, which are then utilized in the calculation of ACE, which is addressed in the Reliability Standards and requirements indicated above. This creates a potential redundancy of these obligations that could be eliminated.MISO respectfully suggests that the references to Pseudo-Ties should be removed from INT-004-3, Requirements R1-R4 and INT-009-2, Requirement R1. Requirement R2 of INT-009-2 should be removed in its entirety. If the Coordinate Interchange Standard Drafting Team moves forward with tagging Pseudo-Ties, we recommend that language be included that would allow an alternate method for reporting Pseudo-Ties, if they are included in a congestion management procedure such as market flows. Additionally, INT-004 R3.1 needs further clarification so only the BA with the in-kind scheduled loss is required to verify the loss.INT-006To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the

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	industry for comment and voting, that would be adequate. MISO respectfully submits that all of INT-006 could be removed; however, at a minimum, R1 and R6 are the best candidates for removal.If the Coordinate Interchange Standard Drafting Team moves forward with INT-006, the MISO suggests the “shall deny” language in R2.1 be changed to “shall evaluate.” “Denying” is a right of the BA rather than an obligation when it comes to BA’s own capability. For example, if BA default ramp limit is 500 MW import, but in real time BA determines that it can handle one more schedule, it should have the right to approve that schedule.INT-009The purpose of INT-009-2 is to ensure that entities are operating to a common, but opposite Net Scheduled Interchange (“NSI”). The inputs to the NSI and Net Actual Interchange are then utilized in the calculation of ACE, which is addressed in BAL-005, Requirements R9-R12. Accordingly, the requirements set forth in INT-009-2 are essentially the inputs to the requirements contained in BAL-005, Requirements R9 - R12. The potential redundancy of these obligations could be eliminated if BAL-005 was modified for enhanced clarity including ensuring that inputs that are currently described in INT-009-2 are addressed in BAL-005-0.2. Such consolidation would provide benefits to reliability generally by ensuring that all obligations relative to the inputs into ACE are clearly described in one location and would eliminate the need for this Standard, which aligns with current efforts to ensure that there is not redundancy in the Reliability Standards. MISO respectfully suggests that the drafting team consider this redundancy as they finalize these standards.INT-010In implementation, Requirements R1 through R3 are essentially “administrative” as they ‘document’ the flow and associated actions after-the-fact. Because the operating time in which the actions and flow were necessary has already elapsed, it is important to note that Requirements R1 through R3 are not necessary for the reliability of the Bulk Electric System. Therefore, while it is good practice to document such activities, such documentation obligations are not appropriate for inclusion in the Reliability Standards. More specifically, the Reliability Standards should contain only requirements for activities that are necessary to maintain the reliability of the Bulk Electric System. After-the fact documentation activities do not meet this essential criterion for inclusion as requirements in the Reliability Standards. MISO respectfully suggests that such requirements be documented in best practices outside of the Reliability Standards. Further,

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	MISO respectfully requests that, if Requirement R1 is retained, the language is revised to ensure that the requirement more clearly states that its intended application is to After-The-Fact reliability adjustments.R4 is trying to ensure that the 'expedited' approval process reserved for reliability reasons is not utilized for non-reliability reasons. This documentation will only be reviewed "after-the-fact" and will not ensure that obligations and process are properly fulfilled and utilized in the normal course of business. Because the operating time in which the relief was requested has already elapsed, it is clear that Requirement R4 is not necessary to ensure the reliability of the Bulk Electric System. Therefore, while it is good practice to document the condition that prompted a request for relief, such documentation obligations are not appropriate for inclusion in the Reliability Standards because the Reliability Standards should contain only requirements for activities that are necessary to maintain the reliability of the Bulk Electric System. After-the fact documentation activities do not meet this essential criterion for inclusion as requirements in the Reliability Standards. MISO respectfully suggests that such requirements be documented in best practices outside of the Reliability Standards. MISO further notes that such documentation activities may distract entities by requiring the relation of real-time BES events to congestion management actions when such entities and their personnel should remain focused on relieving the system conditions. Finally, the requirement does not appear to leverage existing processes. For example, when a curtailment is requested through the IDC, many entities indicate the constrained element in the curtailment request. An alternative approach would be to require a reference to the initiating system condition at the time the relief is requested. More specifically, a reliability adjustment should not proceed through the curtailment process without the identification of the constrained element or condition in the adjustment request. MISO supports the expedited curtailment approval process set forth in Requirement R5. MISO respectfully suggests that Requirement R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule that is already covered by an existing process, i.e., when someone gets a Tag curtailment, they have received notice to adjust the source generation. INT-011MISO requests clarification regarding how the INT-011 standard will be coordinated with changes to the IRO-006 Standards. Currently, IRO-006-EAST-1 R.3 has no provision for the Reliability Coordinator

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	issuing a TLR to instruct the receiving Reliability Coordinator to curtail intra-Balancing Authority Area Point to Point Transmission Service, and IRO-006-EAST-1 R.4 has no provision for the receiving Reliability Coordinator to instruct the Balancing Authority to implement intra-Balancing Authority Point to Point Transmission Service schedule change requests.
MRO NERC Standards Review Forum (NSRF)	The NSRF wishes to thank the CISDT and recommend the following recommendations:Tagging of Pseudo-Ties (INT-004 and INT-009)We do not agree that Pseudo-Ties need to be tagged, because the asset generator defines the reliability impact, and the allocation (tagging discussion) only deals with allocation of energy which is a business practice. The references to Pseudo-Ties should be removed from INT-004 R1-R4 and INT-009 R1-R2. INT-006At a minimum, R1 and R6 are the best candidates for removal, though all of INT-006 could be removed.To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the industry for comment and voting, that would be adequate. INT-009BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of these requirements. Thus, this Standard would no longer be necessary. When specifically reviewing R3, although this requirement has been present since the original policy language was converted to standards; it is an obvious function that is required in order for the flow to be set as desired. This is comparable to generators needing to be told where to operate but there is no requirement for ‘who’ to notify them. INT-010R1-R3 are administrative to ‘document’ the flow after-the-fact. Real Time has already passed so it is not necessary for reliability. It is good practice to do these activities but they should be documented in best practices outside of the requirements.R4 is simply trying to enforce that entities don’t use the ‘expedited’ approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 may have some reliability value in that we desire an expedited

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	process to have a curtailment approved.
ISO New England Inc.	We agree with the Independent Expert Panel's recommendation that a number of the Reliability Standards are being addressed through the functional specifications. INT-004ISO-NE does not currently have interchange associated with dynamic transfers. However, where dynamic transfers are utilized we believe that the transparency these requirements provide is necessary for reliability.INT-006Based on the ISO-NE market design, ISO-NE needs only a net interchange with our neighbor to operate reliably. The details of what customer transactions make up that net interchange is purely commercial/financial under our market design. ISO-NE also does not have loop flow issues with our neighbors and the individual transaction information is not required to manage congestion on our system. If these INT-006 requirements were not contained in NERC standards and interchange transactions are not acted upon in the timeframes defined in these requirements, the ISO-NE markets would continue to economically dispatch generation with respect to any interchange that is available. If no interchange were available the ISO-NE markets have mechanisms in place to ensure that load is served. As such, ISO-NE agrees with the Expert Panel's observation that guidelines exist in the functional specification for electronic tagging. However, the details in that specification were developed based on the language in these standards. If these requirements are removed from the NERC standards, they must reside somewhere in business language that can be voted on by the industry that would continue to drive changes to the eTag specification. If this information were located in a NAESB Business Practice Standards, which are the source of the software specifications, and are open to the industry for comment and voting, that approach would be adequate to serve the reliability needs of ISO-NE. INT-009ISO-NE believes that BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of R1 and R2 of INT-009. INT-009 R3has been present in some form since the original policy language was converted to standards. While it is an obvious function that is required in order for the flow to be set as desired, this is comparable to generators needing to be told where to operate but there is no NERC requirement for 'WHO' to notify them. We believe this requirement can be

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	removed.INT-010R1-R3 are administrative tasks to document the flow directed by an RC after-the-fact. Since they are after-the-fact actions, they are clearly not necessary for reliability. While we agree is necessary for transparency we believe it would be adequate to locate this requirement in a NAESB Business Practice Standard. R4 is trying to enforce that entities do not use the ‘expedited’ approval process for non-reliability reasons. ISO-NE believes a description in NAESB business practices would be adequate. R5 can impact reliability; an expedited process is needed to ensure curtailments occur in a timely manner.. However, since an RC can direct an entity to take action without an approved eTag, it may be adequate to have the NAESB Business Practice Standards define who those approval entities must be to support the software design that would occur for typical interchange processing. The description in the Background section for R6 does not quite align with the requirement language. We believe that R6 could be unnecessary if the language in BAL-005 R9-R12 are updated to use results based standard language. This proposed requirement seems to more of an instruction of HOW someone with a Dynamic Schedule should follow a reliability adjust; and may be more appropriate in the Guidelines and Technical Basis section of INT-004. Another observation/question, is the language in INT-004 R2.3 intended to have the same outcome? There are other NERC Standards that require operating entities to follow directions of their RC, TOP and BA, so this is already covered elsewhere.
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	We agree with the SDT’s disposition of the Paragraph 81 recommendations in the current draft of the INT standards posted. Southern Company would like to take this opportunity to point out that there will be additional burdens and administrative tasks from a compliance perspective due to changes introduced in the current INT proposed standards, namely the requirement to E-tag Pseudo-Tie transactions. Southern believes that the current implementation of the IDC allows for adequate representation of Pseudo-tie transactions for consideration in reliability curtailments. It appears to us that the requirement to E-tag Pseudo-Tie transactions will result in increased regulatory exposure for entities with little net benefit to

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	the overall reliability of the bulk electric system.
Independent Electricity System Operator	We do not believe that any specific requirements in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard.We generally agree with the recommendations that a number of the INT standard requirements can be addressed through the functional specifications of E-tag, especially those that address information exchange at the Arranged Interchange stage. Still, the requirements for the e-tag submission process need to be retained somewhere. If this process is to be moved over to NAESB's business practices, then it is important that coordination with NAESB be initiated as soon as possible to ensure its business practices are ready for implementation when the revised INT standards become effective.
SERC OC Review Group	We recommend that the SDT consider utilizing existing functionality through the ownership factor in the IDC to document real time flows and impacts of Pseudo Ties. The concern is the compliance risk and administrative overhead to adjust these tags on an hourly basis.INT-004-3The SDT is requested to clarify Requirement 3.3.2. Each of the Balancing Authority's associated Reliability Coordinators (in the Eastern Interconnection) or associated Transmission Operators (in the Western Interconnection) has confirmed that sufficient information to reliably manage the Pseudo-Tie has been provided. Modify statement: Pseudo Tie Tags will require adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and internal processes. The existing functionally in the IDC, (add: when used, and current reporting of market flows,)(delete: if made a requirement) will provide greater visibility, accountability, and more accurate data-all contributing to increased reliability.The approval and coordination of Pseudo Ties prior to implementation is addressed in R 3 & 4 and should be adequate to provide the necessary visibility and awareness between all impacted BAs, TSPs, and RCs.INT-006-4We recommend that R4 be reworded based on current NERC Glossary. The Glossary

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	currently defines “Reliability Adjustment”, “Arranged Interchange”, and “Curtailment”. We would suggest that the new language read: R4. Each Balancing Authority receiving a Reliability Adjustment (insert: to) Arranged Interchange shall approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 4.1. If a Balancing Authority denies a Reliability Adjustment (insert: to) Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than10 minutes after the denial.Further, we recommend deleting the “Reliability Adjustment Arranged Interchange from the proposed standard.INT-009-2These following two terms (Attaining Balancing Authority and Native Balancing Authority) are different than other standards and customary terminology used in the industry. To avoid potential confusion or error it is recommended that “Source BA and Sink BA” be utilized.Attaining Balancing Authority: A Balancing Authority bringing generation or load into itseffective control boundaries through a dynamic transfer from the Native Balancing Authority.Native Balancing Authority: A Balancing Authority from which a portion of its physicallyinterconnected generation and/or load is transferred from its effective control boundaries to theAttaining Balancing Authority through a dynamic transfer.INT-010-2 We recommend that the term Reliability Adjustment Arranged Interchange be reworded based on current NERC Glossary. The Glossary currently defines “Reliability Adjustment”, “Arranged Interchange”, and “Curtailment”. We would suggest that the new language read: R4. Each Reliability Coordinator, Balancing Authority or Transmission Service Provider that initiates a Reliability Adjustment (insert: to) Arranged Interchange must have experienced one or more of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations]M4. Each applicable entity shall have evidence such as dated and time-stamped logs, voice recordings, electronic records, or other similar evidence that when it created a Reliability Adjustment (insert: to) Arranged InterchangeR5. Each Sink Balancing Authority shall distribute any Reliability Adjustment (insert: to) Arranged Interchange only to the Source Balancing Authority for reliability assessment. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations]M5. The Sink Balancing Authority shall have

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	evidence such as dated and time stamped electronic logs or other similar evidence that it distributed any Reliability Adjustment (insert: to) Arranged Interchange only to the Source Balancing Authority for reliability assessment. (R5)R6. Each Balancing Authority involved in a Reliability Adjustment (insert:to)Arranged Interchange involving a Dynamic Schedule shall use agreed upon values that ensure any limit established by the Reliability Adjustment Arranged Interchange is not exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations]M6. The Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that following any Reliability Adjustment (insert: to) Arranged Interchange involving a Dynamic Schedule it used agreed upon values that ensured any limit established by the Reliability Adjustment Arranged Interchange was not exceeded. (R6)Further, we recommend deleting the "Reliability Adjustment Arranged Interchange from the proposed standard.The SDT is request to clarify the term "energy sharing" used in R1: Each Sink Balancing Authority shall ensure that a Request for Interchange is created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement NAESB Business Practice Standards - There is a concern among the group on how the NERC Reliability Standards will remain in lock-step with the NAESB Business Practice Standards. Has there been an agreement reached on a process to use?The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
SPP Standards Review Group	We take note of the inclusion of a tagging requirement for Pseudo-Ties that currently does not exist and wonder what has led the drafting team to reach this conclusion. We also wonder if this change will result in significant reliability improvements worthy of the extra effort needed to implement the change. That being the case, we could support the exclusion of Pseudo-Ties from the tagging requirements in INT-004-3 and INT-009-2.INT-004-3We have concern with including requirements (R4) that are dependent upon the existence of a registry in NAESB that

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	currently doesn't exist. How will we be notified when the registry is implemented and how can we be assured that we will be given adequate time to make the proper submittals? We wonder why R4 was even included in the draft INT-004-3 given this situation.There was no explanation given as to what the drivers were for making the definition changes to several key terms. Could the drafting team please provide some reasoning here, especially regarding the replacement of Interchange Transaction Tag with Request for Interchange?Replace 'real time' with 'Real-time' in the definitions of Dynamic Schedule and Pseudo-Tie. The latter is in the NERC Glossary of Terms. Make the same change in Requirement 3.1.In Section 5. Background, delete the 'that' at the end of the 4th line in the first bullet.Insert 'when' in M4 such that it reads: The Balancing Authority shall have evidence (...) that it only approved a Pseudo-Tie Arranged Interchange when the Pseudo-Tie is registered in the NAESB Electric Industry Registry.Reword the Severe VSL for R3 such that it reads: The Balancing Authority approved a Pseudo-Tie Arranged Interchange for a Pseudo-Tie and neither Part 3.1 nor Part 3.2 were met.In the Guidelines and Technical Basis Section in the Application Guidelines, be sure that Dynamic Schedule and Pseudo-Tie are capitalized properly.In the table in the Application Guidelines, capitalize Frequency Bias. It is a NERC defined term. Also, shouldn't consideration be given to manual load shedding outside of an EEA event which is included in the table?INT-006-4Adjacent Balancing Authority is listed in the Definition of Terms Section but it is the same definition as that in the NERC Glossary of Terms. Why is it listed? Shouldn't it be removed?Replace the 'or' with an 'and' in the 4th line of M4.INT-009-2Insert 'and Pseudo-Ties' following Dynamic Schedules in the 3rd line of M1. Also make this same insertion in the Severe VSL for R1.Replace the 'the' in front of HVDC tie with an 'an' in the 1st line of R3 and the last line of M3. Also make this same change in the Severe VSL for R3.INT-010-2Capitalize real-time in Requirement 4.5 and in M4.

END OF REPORT