NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on SAR to Modify and Update Coordinate Interchange Standards — Project 2008-12

The Coordinate Interchange Standard Drafting Team thanks all commenters who submitted comments on the 1st draft of the SAR to modify and update Coordinate Interchange standards. These standards were posted for a 30-day public comment period from July 2, 2008 through July 31, 2008. The stakeholders were asked to provide feedback on the SAR through a special Electronic Standard Comment Form. There were more than 22 sets of comments, including comments from more than 100 different people from approximately 50 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/~filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

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, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

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

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Guy Zito	NPCC RSC										x

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Thompson	Consolidated Edison Co. of New York, Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Frederick White	Northeast Utilities	NPCC	1
5.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
6.	Ron Falsetti	Independent Electricity System Operator	NPCC	2
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Randy MacDonald	New Brunswick System Operator	NPCC	2
9.	Gregory Campoli	New York Independent System Operator	NPCC	2
10.	Michael Ranalli	National Grid	NPCC	3
11.	Ronald E. Hart	Dominion Resources, Inc.	NPCC	5
12.	Ralph Rufrano	New York Power Authority	NPCC	5
13.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
14.	Michael Gildea	Constellation Energy	NPCC	6
15.	Brian D. Evans-Mongeon	Utility Services	NPCC	6
16.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
17.	Brian Hogue	NPCC	NPCC	10
18.	Alan Adamson	New York State Reliability Council	NPCC	10
19.	Guy Zito	NPCC	NPCC	10
20.	Lee Pedowicz	NPCC	NPCC	10
21.	Gerry Dunbar	NPCC	NPCC	10

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
2.	Thad Ness	American Electric Power	x		x		x	x				
3.	Robert Sullivan	California ISO		x								
4.	Jim S. Griffith	SERC OC Standards Review Group	x		x		x					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robert Thomasson	Big Rivers Electric Cooperative	SERC	1, 3, 5
2.	Jim Case	Entergy	SERC	1, 3, 5
3.	Raymond Vice	Southern Co.	SERC	1, 3, 5

	Additional Member	Additional Organization	Region	Segment Selection
4.	Marc Butts	Southern Co.	SERC	1, 3, 5
5.	J. T. Wood	Southern Co.	SERC	1, 3, 5
6.	Mike Oatts	Southern Co.	SERC	1, 3, 5
7.	Jim Busbin	Southern Co.	SERC	1, 3, 5
8.	Roman Carter	Southern Co.	SERC	1, 3, 5
9.	Carter Edge	SERC Reliability Corp.	SERC	10
10.	John Troha	SERC Reliability Corp.	SERC	10

	Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
5.	Jeffery V. Hackman	Ameren	x									
6.	Ron Falsetti	Ontario IESO		x								
7.	Anthony Jankowski	We Energies			x	x	x					
8.	Robert Rhodes	SPP – Operating Reliability Working Group (ORWG)	x	x	x	x	x					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Boshears	City Utilities, Springfield, MO	SPP	1, 3, 5
2.	Brian Berkstresser	Empire District Electric	SPP	1, 3, 5
3.	Bill Bateman	East Texas Electric Coop	SPP	3, 4
4.	Lisa Carter	Southwest Power Pool	SPP	2
5.	Mike Gammon	Kansas City Power & Light	SPP	1, 3, 5
6.	Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
7.	Danny McDaniel	CLECO	SPP	1, 3, 5
8.	Kyle McMenamin	Southwestern Public Service	SPP	1, 3, 5
9.	Eddy Reece	Rayburn Country Electric Coop	SPP	3, 4
10.	Robert Rhodes	Southwest Power Pool	SPP	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Joe Knight	Great River Energy	x		x		x	x				
10.	Marie Knox	MRO NERC Standards Review Subcommittee (NSRS)		x								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	Wisconsin Public Service	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Carol Gerou	Minnesota Power	MRO	1, 3, 5, 6
4.	Jim Haigh	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Tom Mielnik	MidAmerican Energy Company	MRO	1, 3, 5, 6
7.	Pam Sordet	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Larry Brusseau	Midwest Reliability Organization	MRO	10
13.	Mike Brytowski	Midwest Reliability Organization	MRO	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Shane Jenson	Omaha Public Power District	x		x		x				x	
12.	Denise Koehn	Bonneville Power Administration	x		x		x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Wes Hutchison	Transmission Operational Analysis & Support	WECC	1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Kristy Humphrey	Power Scheduling Coordination	WECC	3, 5, 6
3.	Fran Halpin	Generation Support	WECC	3, 5, 6
4.	Bart McManus	Transmission Technical Operations	WECC	1
5.	Troy Simpson	Transmission Bus Process & Implementation	WECC	1
6.	Joel Jenck	Power Scheduling Coordination	WECC	3, 5, 6

			1	2	3	4	5	6	7	8	9	10
13.	Jim Cyrulewski	Functional Model Working Group								x		
14.	Kris Manchur	Manitoba Hydro	x		x		x	x				
15.	Sandra Shaffer	PacifiCorp	x		x		x					
16.	Greg Rowland	Duke Energy Corp.	x		x		x	x				
17.	Eric Grau	Tennessee Valley Authority									x	
18.	Marie Knox	Midwest ISO Stakeholders Standards Collaborators		2								

Additional Member	Additional Organization	Region	Segment Selection	
1.	Nicholas Browning	Midwest ISO	RFC	2
2.	Barb Kedrowski	We Energies	RFC	3, 5
3.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
4.	Joe Dobes	NIPSCO	RFC	1
5.	Roger Huhn	NIPSCO	RFC	6
6.	Bill SeDoris	NIPSCO	RFC	3
7.	Kirit Shah	Ameren	SERC	1
8.	Sam Ciccone	First Energy	RFC	1
9.	Dave Folk	First Energy	RFC	1
10.	Rob Martinko	First Energy	RFC	1
11.	Doug Hohlbaugh	First Energy	RFC	1

			1	2	3	4	5	6	7	8	9	10
19.	Patrick Brown	PJM Interconnection, L.L.C.		x								
20.	Mark W. Hackney	Arizona Public Service Company (AZPS)	x									
21.	Sam Ciccone	FirstEnergy	x	x		x		x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Doug Hohlbaugh	FE	RFC	1, 3, 5, 6
2.	Dave Folk	FE	RFC	1, 3, 5, 6
3.	Rob Martinko	FE	RFC	1, 3, 5, 6
4.	Larry Hartley	FES	RFC	3

			1	2	3	4	5	6	7	8	9	10
22.	Mark Heimbach	PPL EnergyPlus						x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	John Cummings	PPL EnergyPlus	WECC	6

			1	2	3	4	5	6	7	8	9	10
23.	Steve Ruechert	WECC										x

1. Do you agree that there is a reliability-related reason for the proposed standard action?

Organization	Question 1:	Question 1 Comments:
NPCC	Yes	Regional interchange and improving the clarity of functional responsibilities among entities has a direct impact on reliability.
AEP	Yes	The applicability for the responsible functional reliability entity needs to be more realistic to the actual operating model and include any entities that can impact or compromise the ability to ensure reliability.
CAISO	Yes	
SERC OC Standards Review Group	Yes	
Ameren	Yes	
Independent Electricity System Operator - Ontario	Yes	
We Energies	Yes	Must have clear responsibilities in standards.
Operating Reliability Working Group (ORWG)	Yes	
Great River Energy	No	INT-001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT-006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? INT-008-2 - Yes.
MRO NERC Standards Review Subcommittee (NSRS)		Please note that question 1 is different than the word form provided on the website. The word comment form states, "Do you agree that there is a reliability-related reason for the proposed standard action?" and offers the options of Yes, No, and Yes and No. Our group responded with "Yes and No" and offered the comments listed below:INT-001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT-006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a

Organization	Question 1:	Question 1 Comments:
		transaction a month out? a day? an hour?INT-008-2 - Yes.
OPPD	Yes	
Bonneville Power Administration	Yes	
Functional Model Working Group	Yes	
Manitoba Hydro	Yes	
PacifiCorp	Yes	
Duke energy	No	The scope of the SAR appears administrative, and not reliability-related. However we do believe the standards need to be revised to address those items.
Tennessee Valley Authority	Yes	TVA agrees with the comment that referring to e-tag only describes the requirements and technical specifications to implement an electronic transaction information system. It provides a basis for tools designed to facilitate interchange transaction information between two parties. It does not specify "the tool," only what the tool must be capable of doing.INT-001-2: TVA is in favor of including a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers. Although the IDC does not currently use this information, the BAs use it in their forward reliability analysis.
Midwest ISO Stakeholders Standards Collaborators	No	Regarding INT-001-2, no, we do not agree. Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" Regarding INT-006-2, no, we do not agree. TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for E-Tag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? Regarding INT-008-2, yes, we agree.
PJM Interconnection	No	Regarding the purpose of the SAR as stated in the body of the SAR (i.e. not including FERC directives): The stated purpose of the SAR (the last sentence in the PURPOSE section) is "to revise …INT standards to reflect that the IA functions ARE performed by an automated system rather then an entity." PJM believes that NERC standards are written as mandatory obligations assigned to registered entities that in turn are responsible for performing those tasks and who are subject to non-compliance penalties. Thus the stated purpose (to reflect/assign the IA tasks to an automated system) conflicts with that concept. PJM also believes that NERC Interpretations are used to explain implementation issues. Thus the SAR's stated purpose, as noted above, would fall into this latter category.

Organization	Question 1:	Question 1 Comments:
		PJM agrees that it is appropriate to change and/or revise existing requirements to ensure that each requirement is assigned to an owner or operator of the bulk power system and not to a tool. Thus we agree with the stated justification in that same PURPOSE section, that is, there is a need to "resolve the discrepancy" and the confusion related to the IA Function. But there is not so much a need for a change in the standards as there is for an interpretation of those standards. PJM supports NERC's current standards that identify the reliability need for verifying Interchange transactions and that recognize that group of tasks as a unique functional set of tasks that CAN BE assigned and complied with by an entity that can be (but not necessarily is) an RC, BA, or any other registered entity. Moreover, PJM supports the NERC registration process that in the absence of any one or more entities agreeing to register as an IA, and until one or more entities register as IAs, to register all BAs to be responsible for those tasks assigned in the INT standards to the IA Function. Regarding Attachment 1 to the SAR: Attachment 1 (FERC Order 693) FERC Order 693 under INT-001-2, Interchange Information, directs NERC to "include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and 'non-Order No. 888' transfers." PJM supports internal Network transactions and does not recognize internal point-to-point transfers within our Balancing Authority area. All previous grandfathered point-to-point transactions have been closed out. While PJM does support the tracking of interchange in, out, or through a balancing authority as necessary, PJM opposes any attempt to redefine Network transactions as point-to-point transactions particularly since Network market flow is already included in TLR cuts, thus this suggestion is over-reaching in its impacts. INT-006-2: PJM supports the FERC proposal to ensure that the correct functional entities are mandated to approve each transaction. PJM would note that RCs are already mandated by IRO-005-2 R2 to monitor all transactions. And R3 to ensure all TOPs and BAs are notified of any added transactions that would cause an operating limit violation not identified by the TOP. Thus the current INT and IRO standards, as written, allow transactions to be implemented as long as those transactions do not impact Operating Limits. In addition, the current standards mandate monitoring, not direct involvement of RCs, in each transaction. This approach allows reliability to be maintained without adding unnecessary administrative overhead on RCs.
Arizona Public	Yes	

Organization	Question 1:	Question 1 Comments:
Service Company (AZPS)		
FirstEnergy	Yes	We agree. Standards should only be applicable to an owner, operator or user of the bulk power system, and until these standards include this important concept, reliability of the BES will not be ensured.
PPL EnergyPlus		
WECC	Yes	Coordination of Interchange between Balancing Authorities and Transmission Operators is required for proper frequency control, control of flow on the transmision system and overall reliable operation of the Bulk Electric System. The current INT Standards as a whole do not assign clear responsibility to a user owner or operator of the Bulk Electric System for ensuring coordination. In addition the current INT Standards to not adequately recognize that the reliability impact of individual interchange transactions may vary depending on the magnitude of the transaction, the timing of the requests, the type of request and the current operational state of the Bulk Electric System
Response:		

2. Do you agree with the scope of the proposed standard action?

Organization	Question 2:	Question 2 Comments:
NPCC	No	Although the proposed SAR addresses several issues that would improve Interchange Standards, it should more clearly address the need for clarity on whether the Interchange Authority function is an entity or a function. Towards this end the scope of the SAR should incorporate the functions of the Interchange Authority and establish the Balancing Authority as the responsible entity for the Interchange Authority function.
AEP	No	We agree with the description of the modifications needing to be addressed. The combining of the requirements into a fewer number of standards for chronological flow and reference is an excellent idea and response to identified issues. It does not seem realistic for the sink BA to be responsible for the IA applicability, based on the present NERC IA definition. Business practices and reliability requirements for the scheduling of interchange of pseudo-ties and dynamic schedules need to be addressed and identified in these Standards because of their true real-time impact on the reliability of the Bulk Electric System. Just because an operating or Market entity can move a resource into a Balancing Area electronically or on paper, the resource and its flow impact is still directly related to the physical location and actual flow. Reliably managing congestion is about the true physical flow of resource to the load. If the requirements and business practices to address the reliability impact of dynamic transfers and pseudo-ties are not captured in the reliability standards or tools, reliability will continue to be compromised because the true cause of the congestion will not be properly identified. Not to mention the fact that other operating and Market entities might be unfairly managing congestion and penalized. As long as these two mechanisms for interchange transfer are identified and recognized in the monitoring and reliability assessment requirements and tools, they can be managed for reliable planning and real-time operation of the Bulk Electric System. If not, they become an unidentified burden to the real-time operation and compromise reliability. There should be requirements for modeling and managing the congestion impact of these resources in the NERC Reliability Standards.
CAISO	Yes	
SERC OC Standards Review Group	Yes	
Ameren	Yes	
Independent Electricity System Operator - Ontario	Yes	We generally agree with the scope.
We Energies	Yes	With the addition of removing the applicability of the CIP standards to the IA function.
Operating	Yes	

Organization	Question 2:	Question 2 Comments:
Reliability Working Group (ORWG)		
Great River Energy	No	INT -001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT -006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? INT-008-2 & INT-009-1 -No. The requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not Balancing Authorities. For example, INT-005-2 R1. and R1.1. both state actions that are completed by e-tagging services. This is a problem that was created by an incorrect conversion of Policy 3 into the V0 standards.
MRO NERC Standards Review Subcommittee (NSRS)	No	INT -001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT -006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour?INT-008-2 & INT-009-1 -No. The requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not Balancing Authorities. For example, INT-005-2 R1. and R1.1. both state actions that are completed by e-tagging services. This is a problem that was created by an incorrect conversion of Policy 3 into the V0 standards.
OPPD	Yes	
Bonneville Power Administration	Yes	
Functional Model Working Group	Yes	We generally agree with the scope.
Manitoba Hydro	No	The brief description of the scope does not touch on the necessity to address the issues surrounding dynamically scheduling capacity type schedules. Capacity type transactions using dynamic schedules, need to be assured deliverability. Tagging capacity type transactions at "average expected MW profile values" can create problems, because standard transmission tariff anti-hoarding processes, automatically release unscheduled firm transmission service to the non-firm ATC. SOLs or IROLs could very well be exceeded.
PacifiCorp	Yes	
Duke energy	No	The scope of the SAR seems too large for one drafting team. Rather than using a phased approach the project should be broken up into separate projects.
Tennessee Valley	Yes	INT-008-2 and INT-009-1: TVA agrees with the comment that the standard requirement assigns the requirement

Organization	Question 2:	Question 2 Comments:
Authority		to the BA and not an e-tag spec. The e-tag spec is not a tool, only specifications of what the tool should be capable of doing.
Midwest ISO Stakeholders Standards Collaborators	No	Regarding INT-001-2, no, we do not agree. Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" Regarding INT-006-2, no, we do not agree. TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for E-Tag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? Regarding INT-008-2 and INT-009-1, no, we do not agree. The requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not Balancing Authorities. For example, INT-005-2 R1. and R1.1. both state actions that are completed by e-tagging services. This is a problem that was created by an incorrect conversion of Policy 3 into the V0 standards.
PJM Interconnection	No	PJM does not see a need to rewrite the current standards, but does agree that there is a need to provide a final interpretation for the requirements in question. Thus the scope of the SAR is incorrect.
Arizona Public Service Company (AZPS)	Yes	I agree that clarity is needed in the standards in order to implement them and address issues within FERC Order 693. I don't think that the interchange authority must be a physical entity, but can be a software implementation of the process without requiring the vendor to be labeled as a functional entity.
FirstEnergy	No	Our answer to Question 2 is actually "Yes and No" - Comment: See our other comments.
PPL EnergyPlus		
WECC	Yes/No	In general I agree that the items identified in the scope should be addressed but are concerned that the scope is too large, too diverse, and encompasses too many separate standards to be achievable in a reasonable amount of time. I believe this SAR should focus on what is identified as the first phase of this project related to correct assignment of responsibility to a user owner or operator of the Bulk Electric System, I would also support expanding this phase one scope to include ensuring the individual requirements and violation severity levels are proportional to the impact on reliability and the incorporation of directives from FERC Order 693 where these directives relate to assignment of responsibility to user, owners or operators of the BES, The remainder of scope would be more appropriately addressed in a separate SAR.
Response:		

3. Do you agree with the applicability of the proposed standard action? If not, what functional entities do you think need to be added/deleted?

Organization	Question 3:	Question 3 Comments:
NPCC	No	The Resource Planner and Generator Operator Reliability Functions should not be included.
AEP	No	With the evolution from responsibilities of the previous traditional Control Area to present specific entities in the NERC functional model, ownership for some of the responsibilities to ensure reliable operation of the Bulk Electric System has been lost or left to gray areas of implied assumption. The present Balancing Authority functional entity no longer owns or directly controls all of the resources and interchange schedules, as it once did in the prior traditional utility and control area model. Since the Interchange Authority software tool has evolved to become the primary source of communication, coordination, and distribution for request for interchange to be reliably assessed and implemented into the ACE equation, all reliability functional entities need to be properly modeled in the tool and involved in the assessment validation process. If the applicability to the specific reliability functional entity is going to be identified in the NERC Reliability Standard, then the electronic software and Interchange Authority tool must have that particular entity on the approval rights path. This is not necessarily always true today, nor does the IA software match the NERC functional model. A Market affiliate or Creating Purchasing Selling Entity can submit an E-Tag in which a Generator Operator or designee is not involved in the E-tag reliability assessment validation process. This can lead to invalid and misleading approval from the remaining reliability functional entities, such and the BA and TO because the actual Generator Operator resource is not physically capable of matching generation to submitted E-Tag schedule time and ramp. Thus, the former traditional utility/CA and now BA becomes the default provider with the burden to balance and regulate for reliability performance criteria. Generation Operators with submitted resource plans should be in the E-Tag reliability assessment, validation, and approval process to ensure the resource can match what the PSE submits on an E-Tag as the request for interchange. If not, the PSE should have some applicability and accountability as a functional reliability entity for compliance. Remember, prior the new NERC functional model the reliability operators within the old traditional Control Area did the purchasing and selling with reliability being the primary focus, instead of financial. Since the PSE now performs that function, there has to be some direct applicability and accountability in the NERC BAL and INT Reliability Standards or the other responsible functional reliability entities are compromised. The Interchange Authority tool and E-Tag applicability, requirements, and specifications should be referenced in the NERC Reliability Standard. The present IA tool does not exactly match the reliability functional entities. There is still reference to Load and Generation Control Area, instead of the functional model's responsible reliability entities, such as the BA, TO, & GO etc. TP, a Transmission Planner in the NERC registered functions (is a Transmission Provider in the IA tool?). Therefore, there should be strong argument for the proposed SAR and identifying the proper reliability functional entities and accountability ownership.

Organization	Question 3:	Question 3 Comments:
CAISO	Yes	
SERC OC Standards Review Group	No	What is the justification for these standards to be applicable to the Resource Planner function? We believe it should be deleted.
Ameren	Yes	
Independent Electricity System Operator - Ontario	No	We disagree with including Resource Planner and Generator Operator as applicable entities. These entities are not assigned any requirements in these standards, nor are they expected to be assigned any responsibilities given the scope of the proposed changes.
We Energies	Yes	The specific responsibilities of the BA and IA need to be clear. There should not be a "default" responsible entity of the BA. If vendors are the key entities, it should be clear in the standards.
Operating Reliability Working Group (ORWG)	No	We are struggling trying to determine why the Resource Planner and Generator Operator are included on the applicability list. Also why isn't the Load-Serving Entity included on the list?
Great River Energy	No	The activities in the Interchange standards need to clearly identify the responsible entity. GRE believes the Interchange Authority (IA) requirements should be retired.
MRO NERC Standards Review Subcommittee (NSRS)	No	The activities in the Interchange standards should clearly identify the responsible entity. The MRO believes the Interchange Authority (IA) requirements should be retired.
OPPD	Yes	
Bonneville Power Administration	Yes	
Functional Model Working Group	No	We disagree with including Resource Planner and Generator Operator as applicable entities. These entities are not assigned any requirements in these standards, nor are they expected to be assigned any responsibilities given the scope of the proposed changes.
Manitoba Hydro	Yes	If it can not be clearly defined who the Interchange Authority is (change the glossary definition) then the IA requirements should be removed or rewritten assigning those responsibilities to another Function type ie: RC or BA.
PacifiCorp		PacifiCorp agrees that there is confusion regarding the Interchange Authority function and that clarity is needed regarding which entities should have responsibility for the activities currently applicable to the Interchange Authority. However, PacifiCorp is concerned with the proposal that one individual party to a transaction be identified as the responsible entity for interchange transactions, either through making the IA requirements

Organization	Question 3:	Question 3 Comments:
		applicable to the Sink Balancing Authority or by requiring that individual entities register as an Interchange Authority. PacifiCorp foresees two significant problems with this arrangement: 1) identifying and tracking, and taking responsibility for, only those transactions for which the Balancing Authority is the Sink will be administratively impossible without a new automated tool and will result in a potentially confusing scenario whereby many entities are responsible for transactions over a single interchange; and 2) designating only one party to a transaction as responsible for the interchange transaction could engender biased decision-making on the part of each responsible entity. PacifiCorp strongly believes that it makes much more common sense to designate a neutral third-party as responsible for the system-wide accuracy of actual and scheduled interchanges. PacifiCorp believes the Reliability Coordinator is the logical entity to fit this role, particularly because an automated tool already exists which performs the interchange authority functions.
Duke energy	No	We don't understand why the Resource Planner is included as an applicable entity.
Tennessee Valley Authority	No	TVA believes that the Interchange Authority as an entity should be removed, and the functional model should be changed to show the IA functions as belonging to the sink BA.
Midwest ISO Stakeholders Standards Collaborators	No	We believe the Interchange Authority function should be deleted from the functional model (FM), as it just causes confusion.
PJM Interconnection	No	See response to FERC directives in Question 1.
Arizona Public Service Company (AZPS)	No	Not sure of the applicability of the Resource Planner or Generator Operator. They've no involvement in interchange transactions not already covered by an existing function.
FirstEnergy	No	FE has the following issues with the applicability: 1. FERC has directed NERC to make the applicability of the approval of interchange transaction tags to the Transmission Operator due to their local area view of the reliability impacts of an interchange transaction and the Reliability Coordinator due to their wide area view. This will impact several entities by requiring installation of new E-Tag terminals and institute a tag approval procedure. Since the pervue of the reliability standards is bulk electric system reliability, we question the need for a local area view approval of an E-Tag since by definition the impacts are local and should not have an impact on BES reliability. The RC wide area view and approval should be sufficient. 2. We do not agree with the applicability to the Generator Operator and Resource Planner:- Historically the GOP has not been charged with interacting with E-tags. The view has always been that the sink entity is the beneficiary of the service and therefore bears the burden of submitting the tag. Per the NERC Functional Model Version 3,

Organization	Question 3:	Question 3 Comments:
		the GOP function merely "receives notice from the PSE if an interchange transaction is approved or denied", and if approved, "provides the BA and TOP with the requested amount of reliability-related services".- The RP does not have any direct responsibilities in the coordination of interchange transactions and should not be directly responsible for any requirements in these interchange standards. Per the NERC Functional Model Version 3, the RP function merely "coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Owners, Transmission Operators, Interchange Authorities, and Regional Reliability Organizations". 3. The LSE is equivalent to a PSE in many respects but not all LSEs are PSEs so the applicability section should include the LSE function.
PPL EnergyPlus		
WECC	No	Disagree with applicability Resource Planner, and Generation Operator, Believe Applicability should include Load Serving Entity. Also disagree with applicability to Interchange Authority, instead standard should allow flexibility for requirements currently assigned to Interchange Authority to be assigned to a Balancing Authority, ISO, RTO or RSG with a default assignment to the Sink Balancing Authority in the event no other user owner or operator of the BES agrees to accept responsibility.

4. If you are aware of any Regional Variances associated with the proposed standard action, please identify them here.

Organization	Question 4:
NPCC	Not aware of any variances.
AEP	
CAISO	
SERC OC Standards Review Group	
Ameren	
Independent Electricity System Operator - Ontario	
We Energies	none
Operating Reliability Working Group (ORWG)	We are not aware of any regional variances.
Great River Energy	None that we are aware of.
MRO NERC Standards Review Subcommittee (NSRS)	
OPPD	
Bonneville Power Administration	
Functional Model Working Group	None.
Manitoba Hydro	
PacifiCorp	PacifiCorp is concerned that in other regions of the country where independent system operators are more prevalent, it may make more sense for Sink Balancing Authorities to be responsible for interchange schedules or other currently identified Interchange Authority responsibilities. In areas where there is an independent operator, that operator may logically take responsibility for interchange schedules as an uninterested party. In the West, without an independent operator, determining which party should be responsible for each transaction is much more difficult as described above.
Duke energy	None
Tennessee Valley Authority	None
Midwest ISO Stakeholders Standards Collaborators	
PJM Interconnection	No

Organization	Question 4:
Arizona Public Service Company (AZPS)	I don't believe that the WECC has requested a Region Variance for it's business practices.
FirstEnergy	At this time, we are not aware of any Regional Variances associated with the proposed standard action. However, the SAR should leave it open for the SDT to explore this during the standard development process.
PPL EnergyPlus	
WECC	No

5. If you are aware of the need for a business practice to support the proposed standard action, please identify it here.

Organization	Question 5:
NPCC	The development of business practices for TLRs is already included in the current NAESB 2008 Annual Work Plan, under Item 1.a.ii.
AEP	
CAISO	
SERC OC Standards Review Group	
Ameren	
Independent Electricity System Operator - Ontario	
We Energies	
Operating Reliability Working Group (ORWG)	Nothing comes to mind at this time. Seeing something in writing, once the SDT posts draft standards, may trigger a response.
Great River Energy	
MRO NERC Standards Review Subcommittee (NSRS)	
OPPD	
Bonneville Power Administration	
Functional Model Working Group	None.
Manitoba Hydro	
PacifiCorp	Not aware of any.
Duke energy	None
Tennessee Valley Authority	None
Midwest ISO Stakeholders Standards Collaborators	
PJM Interconnection	The development of business practices for TLRs is already included in the current NAESB 2008 Annual Work Plan, under Item 1.a.ii.
Arizona Public Service Company (AZPS)	Yes, the WECC has implemented Business Practice Standards that add further clarity and require greater involvement in the interchange process in order to facilitate correct interchange checkout/coordination.
FirstEnergy	At this time, we are not aware of any need for a business practice to support the proposed standard action. However, the SAR should leave it open for the SDT to explore this during the standard development process.
PPL EnergyPlus	

Organization	Question 5:
WECC	If Standard is not revised to mandate a specific software application, business practices may be required to ensure software and communications compatability between the various entities (such as the e-tag specification), Business practices may be required to identify useful but purely administrative or commercial requirements which should be removed from the reliabilty standards.
Response:	

6. If you have any other comments on this SAR that you haven't already provided in response to the previous questions, please provide them here.

Organization	Question 6:
NPCC	The SAR places emphasis on the issue of requirements being assigned to either owners, operators, or users of the BPS and not to the so called ' tools' (i.e., etag) used to coordinate interchange; currently the Interchange Scheduling and Coordination Standards seem to properly assign these requirements to the owners, operators or users and not to industry tools used in interchange. Therefore, including this issue in the SAR, would seem to deflect the focus of the SAR away from the primary issue of Balancing Authority versus Interchange Authority clarification.
AEP	Since the Reliability Coordinator is responsible for the real-time operating wide area view and is actively involved in managing interchange through the IDC software tool for reliability, why shouldn't the RC be in the required front-end reliability assessment approval process and timing table? Would it not be more prudent to have a true reliability assessment window with the RC involved on the front-end, instead of curtailing NSI on the back-end with the IDC after a reliability limit is already exceeded? If the SAR is going to revise the stated INT-Reliability Standards, the submittal and allotted time for the functional reliability entities should be revisited to provide a true reliability assessment window for responsible entities. The timing table should not be Market driven. The proper responsible functional reliability entities should all be included in the applicability requirements and table. The suggestion to make a Sink Balancing Authority(s) the responsible entity for the an entire Interchange Authority process does not seem to be very realistic or possible. Would it not be more prudent to make an entity at the regional or wide area level, such as MISO, PJM, & SPP CBA, the responsible entity for having the process and software tool with specific requirements to the vendor to meet the IA reliability requirements? Better yet maybe NERC should become the Interchange Authority responsible for the process and requirements of communicating and distributing to the other functional reliability entities, as it does with the IDC. The NERC delimitation of IA itself implies that the responsibility for authorization to and between the BAs occurs at the higher regional and wide area level, so why suggest consideration for the responsible party to be a sink BA?
CAISO	
SERC OC Standards Review Group	
Ameren	
Independent Electricity System Operator - Ontario	The SAR proposes to consider requiring the Sink Balancing Authority responsibility for Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications. We suggest the SDT to keep the options open, and consider the various aspects of possibility, for example, an independent entity to register as the IA to perform such function for transactions sourcing from or

Organization	Question 6:
	sinking in a Balancing Authority area. We suggest the SDT consult the Functional Model Working Group on this issue.
We Energies	
Operating Reliability Working Group (ORWG)	We feel that pseudo-ties should be treated comparably to dynamic schedules regarding reliability curtailments. The omission statement in Section 3.4 on page SAR-11 seems to indicate it may be acceptable to exclude pseudo-ties in curtailment considerations.
Great River Energy	All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the Version-0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools aren't users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function should be retired from the functional model (FM), as it just causes confusion. The BA's responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
MRO NERC Standards Review Subcommittee (NSRS)	The activities in the Interchange standards should clearly identify the responsible entity. The MRO believes the Interchange Authority (IA) requirements should be retired. All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the V0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools aren't users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function should be retired from the functional model (FM), as it just causes confusion. The BA's responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
OPPD	The first paragraph under the psuedo-tie section reads: Pseudo-Ties Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. What does "effective operational control" mean? Should we add a definition of it to the NERC Glossary of Terms? There are a lot of wind farms that are jointly owned or are under long term PPA's. Many of these these arrangements utilize psuedo ties to transfer power from the source to the sink control area. To my knowledge, wind farms don't use AGC. I don't think this committee meant to set the bar of "effective operational control" at AGC control, but maybe we should put any questions about that to rest? To my knowledge, the typical control that a host control area would have over a wind turbine is the ability to turn individual wind turbines on or off by feathering their blades. This could be done remotely, or may have to be done by dispatching personnel to the wind farm site. A sink control area thus would have to call the host control area to request 1 or more wind turbines be feathered to reduce output to the psuedo-tie. An additional issue with this type

Organization	Question 6:
	of control is that it common for a company to buy say 10 MWS of a 50 MWS wind farm. EMS typically would model the sink control area to get 20% of the wind farm output. Thus, if a sink control area called and requested the host control area to feather a 5 MW turbine, it would not cut the pseudo-tie reading by 5 MWS, instead it would cut the pseudo-tie reading by 1 MW (20% of 5). The term "effective operational control" would seem to suggest a more rigorous type of control than that typically exhibited by pseudo-tied wind farms. I don't think it was the committee's goal to outlaw existing psuedo-tied wind farms, so I feel we may need to flesh out what "effective operational control" means or simply replace the phrase with something less strict.
Bonneville Power Administration	Dynamic Schedules and Pseudo Ties are very similar in their nature and in their impact on the BES. Whether the transfer is an "Interchange" transaction, "AGC interchange", or a "Non-contiguous Pool Tie" is purely semantics. Both types of transfer involve the movement of power from one point in an interconnection to another. Both involve a variable power signal transmitted via telemetry. Both require that transmission rights be secured in order to move that power from source to sink. And, most importantly, both influence power flowing across flowgates and interties, and thus reliability. Despite the physical similarities, Attachment 2 defines two separate processes for providing information necessary for system reliability. Dynamic schedules have a well defined requirement which includes the submission of e-tags. Pseudo Ties, on the other hand, require no e-tags but rather have a relatively undefined process stating only that BA's must get the information to the IDC, Reliability Coordinator, etc. Dynamic Schedules and Pseudo Ties should have the same requirements for tagging even though they are treated differently in the ACE equation. The Reliability Authority has a need for information on both types of transfers and that information should be collected in a uniform, standardized manner. To do otherwise places one of these similar products at a disadvantage to the other and may violate the first Market Interface Principle - "A reliability standard shall not give any market participant an unfair competitive advantage." The drafting team should strive to find a single process for all dynamic transfers which, gets the necessary information onto the screen of the Reliability Coordinator and others who need this information in a manner which is least disruptive to the operations of BA's involved.
Functional Model Working Group	The SAR proposes to consider requiring the Sink Balancing Authority to be responsible for the Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications. The FMWG supports the notion that the revised set of Coordinate Interchange standards shall ensure that each requirement is assigned to a responsible entity and not to a tool used to coordinate interchange. Many responsible entities employ tools to perform their respective functional tasks. For examples: the Balancing Authority uses tools such as AGC; the Reliability Coordinator and Transmission Operator use tools such as State Estimation and contingency analysis, etc. The tools that an Interchange Authority employs are simply a means to fulfill its obligations like its BA, RC and TOP counterparts. As such, the Interchange Authority should be held accountable for ensuring the interchange information is compiled and communicated timely and properly to facilitate implementation of interchange transactions, in the same way that its BA, RC and TOP counterparts are held accountable for ensure reliable operations of the bulk electric system using whatever tools they see necessary to perform their tasks. On the other hand, we do not agree that the sink BA should be the only

Organization	Question 6:
	entity required in the Coordinate Interchange standards to be responsible for the Interchange Authority functions. Such a restriction would preclude any third party from stepping forward to offer and register for this function - a scenario as described in the Functional Model's Technical Document. We believe the Coordinate Interchange standards should continue to assign the tasks and responsibilities to the Interchange Authority (as the Applicable Entity). The issue with who should register as the Interchange Authority can be addressed by the registration criteria. For transactions sinking in a Balancing Authority area, if no one steps forward to perform the Interchange Authority functions, the default entity is the sink BA. Under this condition, the sink BA should register as the default Interchange Authority for its area.
Manitoba Hydro	Comments regarding INT-001 and INT-004: NERC standards INT-001 and INT-004 require dynamic schedules be tagged at the hourly expected value (INT-001) and adjusted after-the-fact based upon magnitude (INT-004). Dynamic schedules used for capacity type transactions such as AGC regulation, contingency reserves or price sensitive market dispatch should be exempt from these requirements due to their intended purpose. Transmission service both day-ahead and real-time by releasing the unused transmission capacity not scheduled under existing transmission reservations. The unused and available transmission capacity is calculated based upon the maximum hourly capacity of the transmission reservation less its hourly scheduled interchange on interchange transaction tags. Tagging dynamic schedules at average expected values (below maximum values) artificially creates non-firm transmission capacity. This can lead to a situation where SOL and/or IROL levels are exceeded when dynamic schedules are dispatched in excess of their tagged average values and non-firm flows from implemented interchange transactions (a result of transmission capacity freed up from dynamic schedules being tagged at less than their maximum dispatch level) are simultaneously flowing. An example of capacity type transactions on dynamic schedules can be found in the Midwest ISO ancillary services market (expected to launch Sept 9, 2008). In this market External Asynchronous Resources will be dispatched to deliver energy and operating reserves utilizing dynamic interchange schedules tagged at the hourly maximum value. Due to the impending launch of the MISO ancillary services market in September 2008 it is imperative this dynamic scheduling issue be addressed in phase one of this project.
PacifiCorp	None at this time.
Duke energy	We agree that the Dynamic Transfer Reference Document should be left as a reference document and should not become part of the standards.
Tennessee Valley Authority	
Midwest ISO Stakeholders Standards Collaborators	The activities in the Interchange standards should clearly identify the responsible entity. The Midwest ISO believes the Interchange Authority (IA) requirements should be retired. All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the V0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools

Organization	Question 6:
	aren't users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function should be retired from the functional model (FM), as it just causes confusion. The BA's responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
PJM Interconnection	There is a real need to distinguish between Functional Entities and Registration of entities. The IA is a set of reliability tasks that must be performed because without verification by all parties to a transaction there is the potential for inappropriate generation changes caused by incorrect transaction information. The IA tasks can be (but do not have to be) carried out independently of the BA tasks. As the Interchange Subcommittee notes, there can be technological changes in the future. PJM agrees and believes that the current INT standards allow for those changes; and to implement the IS's proposed changes, would preclude a non-BA entity from being an IA. This is a clear violation of the Market Principles 2 and 3.The NERC registration process must ensure that someone is held responsible for each mandated task. NERC can not hold a third-party vendor responsible to comply, but it can hold the entity that uses that third party entity. In lieu of an independent entity/entities registering as IAs, PJM fully supports the registration of BAs as being responsible for complying with the IA tasks.
Arizona Public Service Company (AZPS)	If it is felt that a physical entity must register and take responsibility as the IA, then it is our belief that the WECC, as the contract holder for the software used to perform all the IA functions within the Western Interconnection, would be that entity. But for clarity, it is our belief that the wording in the Functional Model and in the standards is out of step with the reality of present circumstances and that with software being robust and as practical as possible 100 percent available, there is no need for an IA in the FM or Standards.
FirstEnergy	FE has the following additional comments: 1. The SAR proposes to, "Consider requiring the Sink Balancing Authority responsibility for Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the E-Tag Specifications." The rules applied to this tool through the E-Tag Specifications are mostly designed to facilitate the application of Transmission Transaction market rules (many of the transmission transaction market rules ultimately facilitate the energy transactions market) which for the most part support the transmission and energy markets and are not applicable to improving reliability. We suggest a revision to the SAR to point only to the parts of the specifications related to reliability and not just include the E-Tag Specifications as a whole. Also, the E-Tag tool is similar to an EMS system in that it is a tool that is used to provide and promote BES reliability. These standards should be no more invasive then the requirements on network analysis or similar systems contained in an EMS tool. 2. Coordination with other projects and SDTs:- The SAR should indicate some type of coordination with the CIP SDT since the CIP-002 through CIP-009 places requirements on the Interchange Authority. The CIP standards

<table>
<tr><th>Organization</th><th>Question 6:</th></tr>
<tr><td></td><td>will also need to point to the correct owner, operator or user of the BES for the Interchange functions.- NERC Project 2007-14 is in the process of revising INT-005-2, INT-006-2, and INT-008-2. The INT SDT will need to be aware of the latest versions of these standards when they revise all of the INT standards.

3. Definitions - The SAR should also include a review of the current NERC Glossary terms related to interchange to determine if any revisions or new definitions are necessary as a result of the interchange standards development.

4. The SAR indicates "The work in this project should be done in two phases, with the first phase focused solely on clarifying the applicability of each requirement in the existing set of standards. All other revisions should take place in a second phase." FE questions the feasibility of re-assigning the applicability of existing requirements to other NERC Functional Model responsible entities without the ability to concurrently modify requirements to better reflect the real-world interchange transaction process. This concern seems to be supported by the SARs earlier claim that:

a) the Interchange Authority function as defined by the Functional Model does not represent technological advances since the FMWG originally defined the IA function

b) A potential need for requirement references to the E-Tagging process that is presently in practice within industry.

5. FE agrees with the SAR purpose indicating that "Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; ... " In FE's comments to the FMWG related to proposed FM Ver 4 we indicated "The FMWG should give consideration to removing the IA from the FM. The IA Tasks should be re-oriented as needed to the TSP and/or BA entities. The IA does not appear to be a self evident entity to the extent that registration to the IA function will occur. The IDC should be viewed as a tool, not a Functional Model entity, used by the TSP and/or BA to accomplish the described tasks." To this end, we believe the SAR should indicate that the SDT, being comprised of subject matter experts and having reviewed and assessed comments, opinions from a variety of industry stakeholders will at the conclusion of the project provide its recommendation to the FMWG related to the on-going need of the IA functional entity classification.</td></tr>
<tr><td>PPL EnergyPlus</td><td>INT-001-3 Interchange Transaction Tagging Applicability :Reliability Coordinators need to be included because curtailments of dynamic schedules (covered under INT-004-2) will help reduce unscheduled flow and the RC is responsible to be sure that the data on the tag is enough to assure the right tags get curtailed (i.e. zone data, etc.). The Transmission Service Provider may also need to be included because this same logic may apply to conditional firm curtailments.R2.2: The west uses automatic time-error correction which pays inadvertent back</td></tr>
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Organization	Question 6:
	continuously. The magnitude is usually a % of L10 and does not take manual intervention so it might be hard to tag. Should there be an exemption under R2.2 for the WECC time error correction?INT-003-2 Interchange Transaction ImplementationR1: it looks like "net" interchange was inserted then removed. Net is probably useful in this requirement.R1.1: The word RAMP may be useful to have in this section as the sending/receiving BA's must agree on RAMP details.INT-004-2 Interchange Transaction Modifications. It is interesting to note that dynamic schedule tags must be modified if the reserved capacity isn't being fully utilized or more transfer capability is needed (since +/- 10% and +/- 25 MWH covers both more and less than reserved amount). How (practically) will the dynamic schedule get more capacity that reserved? Does this standard need to link to the MOD-001 standard for calculating ATC? It doesn't appear that dynamic schedules deserve any higher priority than any other TSR. Should there be no allowance to exceed reserved capacity (i.e. +0%, -10%) Pre-R1: Do dynamic schedule curtailments need to be addressed in this standard? R2.3: The word "deadband" may be useful here to state an amount beyond which the tag must be modified.INT-005-2 Interchange Authority Distributes Arranged Interchange. This standard only addresses curtailments; does another standard address initiating an emergency tags (as when calling on reserves or starting a quick-start unit, etc.). R1.1: Distribute to all BA's on tag, not just source and sink BA's, otherwise losses supplied by intermediary BA's will cause inadvertent for the intermediary BAs. INT-006-2 response to Interchange Authority. No Comments. INT-007-1 Interchange Confirmation. No Comments. INT-008-2 Interchange Authority Distributes Status. No Comments. I NT-009-1 Implementation of Interchange. No Comments
WECC	Due to the large volume of transaction requests which must be processed, timely communication, assessment, approval and implementation of Interchange requires some type of software or automated process. SAR should ensure standards do not assume or require 100% availability of these systems for compliant operation should address the impact of a failure or malfunction of software or communication systems, and possibly include alternate standard requirements that would allow for reliable and compliant operation during short duration software or communication failures. INT Standards should recognize that implementation of transactions (or failure to implement transactions) needed for immediate system reliability such as curtailments, reloads, emergency assistance and deployment of contingency reserves. have a greater reliability impact than routine commercial transactions, particularly forward transactions or market adjustments. This should be considered when establishing standard requirements and violation severity levels for non-compliance.