Consideration of Comments on Project 2010-10 — Modifications to FAC-012 and FAC-013 for Order 729 — SAR and Draft FAC-013 Standard

The FAC Order 729 Drafting Team thanks all commenters who submitted comments on the proposed SAR and modifications proposed FAC-013-2 — Planning Transfer Capability. These documents were posted for a 45-day public comment period from March 15, 2010 through April 29, 2010. Stakeholders were asked to provide feedback on the standard through a special Electronic Comment Form. There were 15 sets of comments, including comments from over 60 different people from more than 30 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received the drafting team made the following changes to the proposed Standard:

- Modified the definitions of Planning Transfer Capability (PTC) and Planning Transfer Capability Methodology Document (PTCMD).
- Modified the Purpose Statement to clarify that the requirements aim at preparation, not real time use of a methodology for calculating Planning Transfer Capabilities.
- Modified the Effective Date (from six months to twelve months) to allow sufficient time for the Planning Coordinator to prepare its PTCMD.
- Modified Requirement R1 to include data and modeling details and provide clarity.
- Modified the requirement to distribute the PTCMD to a larger group of entities, including entities with a reliability-related need who request the PTCMD
- Added a set of requirements to support peer review of the PTCMD
- Modified all Measures to better align with the Requirements.
- Modified the VRFs to align with the modifications to the Requirements.
- Modified the VSLs to align with the modifications to the Requirements.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.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, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@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.	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.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
18.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Robert Pellegrini		The United Illuminating Company	NPCC						1			
20.	Saurabh Saksena		National Grid	NPCC						1			
21.	Michael Schiavone		National Grid	NPCC						1			
22.	Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC						3			
2.	Group	Stephen Mizelle	Southern Company Transmission	X									
3.	Group	Jason L. Marshall	Midwest ISO Stakeholder Standards Collaborators		X								
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Barb Kedrowski		We Energies	RFC						3, 4, 5			
2.	Joe O'Brien		NIPSCO	RFC						1			
3.	Joe Knight		Great River Energy	MRO						1, 3, 5, 6			
4.	Jim Cyrulewski		JDRJC Associates, LLC	RFC						8			
4.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Laura Trolese		BPA - Transmission Policy Development & Analysis	WECC						1			
2.	Mike Viles		BPA - Transmission Technical Operations	WECC						1			
3.	Pat Rochelle		BPA - Transmission Planning	WECC						1			
4.	Jeff Newby		BPA - Transmission Planning	WECC						1			
5.	James Randall		BPA - Transmission Planning	WECC						1			
6.	Kyle Kohne		BPA - Transmission Planning	WECC						1			
7.	Rebecca Berdahl		BPA - Power Long Term Sales and Purchases	WECC						3			
5.	Group	Patrick Brown	PJM Interconnection		X								
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Don Williams		PJM Interconnection	RFC						2			
2.	Chris Advena		PJM Interconnection	RFC						2			
3.	Mark Sims		PJM Interconnection	RFC						2			
6.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X					
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Bob Jones		Southern Company Services - Trans.	SERC						1			
2.	David Marler		Tennessee Valley Authority	SERC						1			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
3. Charles Long			Entergy	SERC						1			
4. James Manning			North Carolina Electric Membership Corporation	SERC						3			
5. Pat Huntley			SERC Reliability Corporation	SERC						NA			
7.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				
Additional Member			Additional Organization	Region						Segment Selection			
1. Sam Ciccone			FirstEnergy	RFC						1, 3, 4, 5, 6			
2. Dave Folk			FirstEnergy	RFC						1, 3, 4, 5, 6			
8.	Group	Ben Li	IRC Standards Review Committee		X								
Additional Member			Additional Organization	Region						Segment Selection			
1. Bill Phillips			MISO	MRO						2			
2. Lourdes Estrada-Salinero			CAISO	WECC						2			
3. James Castle			NYISO	NPCC						2			
4. Steve Myers			ERCOT	ERCOT						2			
5. Matt Goldberg			ISO-NE	NPCC						2			
6. Mark Thompson			AESO	WECC						2			
7. Charles Yeung			SPP	SPP						2			
8. Patrick Brown			PJM	RFC						2			
9.	Individual	Ross Kovacs	Georgia Transmission Corporation	X									
10.	Individual	Kirit Shah	Ameren	X		X		X	X				
11.	Individual	Dan Rochester	Independent Electricity System Operator		X								
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
14.	Individual	Darcy O'Connell	California ISO		X								
15.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

1. Do you agree that the SAR fully addresses the applicable directives from FERC Order 693 and Order 729?

Summary Consideration: Most stakeholders who responded to this question indicated that the SAR does fully address the applicable directives from FERC Order 693 and Order 729.

A few of the entities providing comments felt that the RC should be removed from the draft standard. There are no references to the Reliability Coordinator in the proposed standard.

A couple of the entities providing comments felt that the standard was implying that it could be used to grant transmission rights. The SDT removed any reference to transfer capability calculations.

A few of the commenters felt that the standard was mandating that the methodologies needed to be consistent rather than the criteria used in the methodology. The SDT modified the standard to include data and modeling details to establish a framework and consistency for the Planning Transfer Capability (PTC) methodology while allowing the Planning Coordinators the flexibility necessary for their individual methodology.

The following was added to Requirement R1 as information (data and modeling details) that must be provided in the Planning Coordinator's Planning Transfer Capability Methodology:

1.1. A description of how each of the following is addressed in the calculation of Planning Transfer Capabilities (PTC), or an explanation for any of the following not used in the calculation of PTC.

- Generation dispatch, including expected outages, additions and retirements
- Transmission system topology, including expected transmission outages, additions and retirement
- System demand
- Current and projected transmission uses
- Parallel path impacts (loop flow)
- Contingencies
- Reliability margins applied to reflect uncertainty with BES conditions.

1.2. A list of all PTC's to be calculated.

1.3. A statement that PTC's shall respect all applicable System Operating Limits (SOL's).

1.4. A statement that the assumptions and criteria used to calculate PTC are as or more limiting than the assumptions and criteria used in the operating horizon.

1.5. A description of how generation/load is adjusted to determine the PTC's identified in 1.2 above.

1.6. A description of the assumptions and criteria used to calculate PTC.

Organization	Yes or No	Question 1 Comment
Ameren	No	Draft Standard does not appear to provide details on the data input and modeling assumptions from Order 693.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Manitoba Hydro	No	Manitoba Hydro does not believe FERC should mandate changes to international standards. Order 729 required elimination of redundancies between FAC-012 and the new MOD standards (1, 28-30). This can easily be accomplished by removing reference to the Reliability Coordinator in R1 through R4. Order 693 required a more detailed framework of the data inputs and modeling assumptions. This could be added as an additional requirement R1.4 in the existing FAC-012 standard. There is no strong reliability need to have a consistent methodology between the operating and planning horizons. However, there should be a need to ensure the methodologies used by adjacent Planning Coordinators for the same interface are consistent. Requirement R4 is a step in this direction in the existing standard but is completely missing in the revised standard. The proposed changes make the Transfer Capability calculations in the 2-5 year period too close to a full operational study. This is not consistent with the direction given by Order 729 and 693 where the numbers are not intended to grant transmission service.
Response: With reference to your comment concerning FERC jurisdiction, this is an issue that is outside the scope of this project. **There are no references to the Reliability Coordinator in the set of proposed revisions to the standard.** **The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.** **The SDT believes that the present communication flow on PTC and PTCMD's is sufficient to ensure reliability and the methods do not need to be consistent.** **The draft standard has been modified to remove any reference to transfer capability calculations for use in ATC calculations in the operational horizon.**		
SERC Planning Standards Subcommittee	No	Order 729 expresses FERC's "concerns" that the criteria used for the calculation of transfer capability be consistent in the Operations and Planning horizons. The SAR as drafted requires Planning Coordinators to document their methods and document the extent to which those methods differ between the operating and

Organization	Yes or No	Question 1 Comment
		planning horizons. The SAR as drafted appears to go beyond the intent of FERC's language in 729 in that it requires methods to be consistent as opposed to criteria. If methods differ, but use the same criteria (i.e. 100% of normal facility ratings), then compliance should be achievable as many entities use different methods in the operating and planning horizons. We agree with the MISO comment that it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed from originally in Order 693.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Midwest ISO Stakeholder Standards Collaborators	No	The SAR appears to fully address the directives; however, it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed in Order 693.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Duke Energy	Yes	However, we don't believe that it's possible to maintain a strict adherence to the FERC directive that the methodology and criteria used to determine Planning Transfer Capability (PTC) in the planning timeframe be identical to, or even consistent with, those used in determining ATC in the operating timeframe. The methodologies and criteria need to be different in some instances because the objectives are different. In the operating timeframe, realistic assumptions and data reflecting the expected operating conditions of the system must be used for determining ATC. In the planning timeframe, different assumptions for operating conditions and contingencies are used to determine how robust the system is in response to more extreme events. For example, a study might examine the impacts of significantly reduced generation from unscrubbed coal plants. Furthermore, analyses in the planning timeframe may use different tools (and thus treat inputs differently) such as PSSE, versus an ATC tool such as MUST.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Southern Company Transmission	Yes	Southern believes the description of the SAR fully addresses the applicable directives from FERC Order 693 and FERC Order 729. Southern interprets the main directives from these respective orders as: 1) modify FAC-12-1 and FAC-13-1 to address calculation and communication of Transfer Capabilities for the timeframe beyond 13 months, 2) modifications to these FAC standards should not address the timeframe from 1 hour through 13 months, 3) modify FAC-13 to be applicable to the Planning Coordinator only and not the Reliability Coordinator, and 4) remove redundant provisions for the calculation of Transfer Capabilities addressed elsewhere in the MOD

Organization	Yes or No	Question 1 Comment
		Reliability Standards. Southern agrees with NERC's interpretation that the revised FAC standards must not conflict with the ATC-related MOD standards as long as NERC's interpretation is that the revised FAC standards do not prescribe additional requirements for the calculation of Transfer Capabilities in the operating horizon. However, Southern would disagree if NERC's interpretation is that the methodologies described in the MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2) must be utilized to calculate Transfer Capabilities for the timeframe beyond 13 months. Southern does not believe that there are existing standards that provide the framework for calculation of Transfer Capabilities beyond 13 months.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has modified the standard to remove any reference to transfer capability calculations for use in ATC calculations in the operational horizon. **The SDT has modified the standard to provide a framework for beyond 13 months.**		
FirstEnergy	Yes	The purpose statement of the SAR states "Address FERC directives from Order 729 Related to FAC-012-1 and FAC-013-1." By extension, Order 729 in paragraph 291 also requires NERC to address its Order 693 directives as well as those explicitly stated in Order 729. The SAR clearly contains excerpted directives from FERC Order 693 and 729 and to the best of our knowledge captures the Commission directives.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Xcel Energy	Yes	The SAR appears to fully address the directives; however, it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed from originally in Order 693.
Response: The SDT thanks you for your affirmative response and clarifying comment. **The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.**		
California ISO	Yes	
Georgia Transmission Corporation	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	
PJM Interconnection	Yes	

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

Summary Consideration: One commenter questioned the relationship between FAC-010-2/FAC-014-2 and FAC-013-2. There is no relationship between FAC-010/FAC-014 and FAC-013.

- FAC-010/FAC-014 deal with calculation and communication of System Operating Limits (SOLs) and the subset of SOLs that are also Interconnection Reliability Operating Limits (IROLs) based on specific criteria contained in the standards.
- FAC-013-2 requires calculation of Planning Transfer Capabilities (PTCs) according to the Planning Coordinator's Planning Transfer Capability Implementation Document (PTCID), based on the Planning Coordinator's own set of criteria. Note that in the revised standard, the PTCID has been changed to Planning Transfer Calculation Methodology Document (PTCMD).

The PTC can be calculated between areas where no SOL has been established; PTC's are calculated to enhance the Planning Coordinator's understanding of the system behavior and not to establish operating limits.

Another commenter stated that it would put a strain on the Planning Coordinator to determine planning horizon PTC's, and that the Transmission Operator would not be interested in Planning Horizon PTC's. The development of PTCs is not unnecessary work; there is a reliability related need to calculate PTC's in accordance with the PTCID (now called PTCMD) based on knowledge of how the system operates. This is consistent with existing industry practice. The standard had been modified and no longer requires the information to be shared with a Transmission Operator.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>BPA would like clarification regarding the relationship between FAC-010-2 and FAC-014-2 and the proposed FAC-013-2, specifically regarding the difference between establishing a System Operating Limit in the Planning Horizon and establishing Planning Transfer Capabilities.</td></tr>
<tr><td colspan="3">Response: There is no relationship between the FAC-010/FAC-14 and FAC-013. FAC-010/FAC-14 deal with calculation and communication of SOLs and the subset of SOLs that are IROL's based on specific criteria contained in the standards and are applicable to different entities. FAC-013 only requires calculation of PTC's according to the Planning Coordinator's PTCID (now called the PTCMD), which is based on the PC's criteria. For instance, PTC may be calculated between areas where no SOL is established. PTC's are calculated to enhance the Planning Coordinators understanding of system behavior not to establish system operating limits.</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>The granularity of the proposed standards action is too great. And there is too much linkage between PTCID and ATCID that is not achievable, or even desirable, since the ATCID addresses transfer capability to support reliable operation of the system, while PTCID addresses planning of the system for reliability under a potentially wide range of future conditions.</td></tr>
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Organization	Yes or No	Question 2 Comment
Response: The SDT believes sufficient flexibility has been afforded by allowing calculation of PTC's according to the Planning Coordinator's PTCMD. **The SDT agrees with your comment regarding the excessive amount of linkage between PTCID and ATCID and has removed all linkage between the two.**		
Manitoba Hydro	No	The SAR requires the PC to complete many detailed studies and verifications. This is unnecessary work in determining planning horizon PTCs.The SAR assumes TOs have a large interest in Planning Horizon PTCs. This is not always the case.
Response: The SDT disagrees and believes there is a reliability related need to calculate PTC's according to the Planning Coordinator's PTCMD based on their knowledge of how the system operates. This is consistent with existing industry practice. This standard has been modified and no longer requires this information to be shared with Transmission Operators.		
SERC Planning Standards Subcommittee	No	We are concerned that more transfer capability studies than are needed will be required.
Response: The SDT has modified the draft standard to better align the number of Transfer Capability studies with what is required for reliability.		
Ameren	Yes	
California ISO	Yes	
FirstEnergy	Yes	
Georgia Transmission Corporation	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
Midwest ISO Stakeholder Standards Collaborators	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 2 Comment
PJM Interconnection	Yes	
Southern Company Transmission	Yes	
Xcel Energy	Yes	

3. Do you agree that the Planning Coordinator is the only functional entity that should have requirements assigned to them as part of this project? If not, please identify to whom the standard should apply and why.

Summary Consideration: A couple of entities that provided comments suggested that this standard was requiring duplication of data already provided for in other standards. The SDT does not believe that there is any duplication.

Some commenters indicated that there may be some gaps in data provision such additional requirements may be needed to ensure the Planning Coordinator has the data needed to calculate Planning Transfer Capabilities. The necessary data and information is available to the Planning Coordinator through requirements in other standards as well as through participation in FERC Order 890 activities - this standard is not requiring additional reporting of the same data.

Another commenter felt that the standard should require coordination of the verification of PTC with the Transmission Planner (TP). Sharing the information with the TP's allowed the TP to review the information and therefore was sufficient coordination.

Organization	Yes or No	Question 3 Comment
Midwest ISO Stakeholder Standards Collaborators	No	The drafting team should review if there are any requirements needed to compel registered entities such as TP, TO, TOP, GO, GOP, and BA to provide any data that the PC needs to complete its function. If the data is already required through other requirements in other standards, then additional requirements are not needed.
Response: The SDT believes the necessary data and information is available to the Planning Coordinator through the requirements of other NERC standards and participation in FERC Order 890 activities.		
FirstEnergy	No	The SAR should allow sufficient flexibility for the drafting team to consider other responsible entities that may be required to support and provide information to the Planning Coordinator in this effort. While we agree that most and possibly all requirements will fall to the PC, the SAR should not be so narrowly written to preclude other entities if needed.
Response: The SDT believes the necessary data and information is available to the Planning Coordinator through the requirements of other NERC standards and participation in FERC Order 890 activities. No additional responsible entities were added to the SAR.		
Ameren	No	We believe that, in R4, PC should coordinate verification of PTC with TP(within PC's planning coordinator area).
Response: The SDT believes that sharing the information with the TP's is sufficient coordination as required in Requirement R5. The SDT added requirements to include peer review of the PTCMD, in support of your suggestion.		

Organization	Yes or No	Question 3 Comment
Xcel Energy	Yes	We agree, however the mapping of entities to Planning Coordinators is an ongoing gap in the registration process. Many entities (primarily non-RTO) are unable to point to who their PC is and similarly, entities who are PCs self define the entities they cover. To our knowledge, there is no source to identify the mapping of these relationships. Therefore, prior to implementation of standards that propose very prescriptive requirements on the PC and their interactions with subordinate entities it is important that the relationships are clearly established as a point of reference.
Response: Your comment concerning the registration process is outside the scope of this project.		
California ISO	Yes	
Duke Energy	Yes	
Georgia Transmission Corporation	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
Manitoba Hydro	Yes	
Northeast Power Coordinating Council	Yes	
PJM Interconnection	Yes	
SERC Planning Standards Subcommittee	Yes	
Southern Company Transmission	Yes	

4. If you are aware of the need for a regional variance or business practice that we should consider with this SAR, please identify it here.

Summary Consideration: Only two entities responded to this question. One entity felt that a regional business practice difference should be considered since WECC allows these calculations to be used to establish path ratings. The draft standard only requires that PTCs be calculated - how PTCs are used or applied is the responsibility of the entity using the PTCs.

The other entity stated disagreement with a need to calculate PTCs. The draft standard only requires PTCs to be calculated where the Planning Coordinator feels there is a need in accordance with its PTCMD - PTCs provide additional important information used when assessing reliability in the planning horizon.

Organization	Yes or No	Question 4 Comment
Duke Energy		none
Xcel Energy	Business Practice	Business Practice: WECC Planning Coordination Committee (PCC) HandbookComments: Entities within WECC may be using this to establish path ratings
Response: The standard requires the calculation of PTC's. How the information is used and applied is the responsibility of the entities using the information.		
PJM Interconnection	Business Practice	PJM does not believe that a transfer capability methodology is the only valid option for the planning horizon. PJM's current, FERC approved, integrated queue study process (part of the PJM Regional Transmission Expansion Planning Process) requires that PJM study the base system and resolve any reliability criteria violations by implementing system upgrades. PJM then studies the integrated queue in the order in which the queued projects were received and resolves any reliability criteria violations by implementing system upgrades. This method ensures that the system as planned does not have any reliability violations. Requiring PJM to use a transfer capability analysis in the planning horizon would require PJM to unwind our current FERC approved integrated queue study process for transmission service, merchant transmission, and generation interconnection.
Response: The revised FAC-013 only requires calculation of PTC's where the Planning Coordinator has determined a need for PTC's to be calculated. PTC's are to be calculated according to the Planning Coordinator's PTCID, which is based on their criteria. This provides additional important information for assessing reliability in the planning horizon.		

5. If you have any other comments on this SAR that you have not already provided in response to the prior questions, please provide them here.

Summary Consideration: There were only two entities who provided comments in response to this question. In both cases the entities appeared to be confusing calculating available AFC/ATC with calculating PTCs. The SDT acknowledged that the first draft of the standard was confusing. The SDT removed all references to transfer capability for use in AFC/ATC calculations in the operational timeframe from the second draft of the proposed standard.

Organization	Yes or No	Question 5 Comment
Duke Energy	No	
Southern Company Transmission	No	
Xcel Energy	No	
PJM Interconnection	Yes	The ATC Methodology used in the operations horizon is fundamentally different than how PJM designs the transmission system to accommodate new requests for transmission service and generation interconnection. Specifically, the long-term Firm transmission service evaluation doesn't start with a Transfer Capability analysis; the AFC/ATC methodology used in planning for operations does.
Response: The draft standard has been modified to remove any reference to transfer capability calculations for use in ATC calculations in the operational horizon.		
Manitoba Hydro		The SAR requires that the PTCID line up with the ATC methodology in the operating horizon (the ATCID). This implies full blown operating studies in the planning horizon (spring. Summer, fall winter years 2 to 5). The accuracy and uncertainty of planning horizon PTCs mean these PTCs will not necessarily allow for transmission service. So why is it necessary for PCs to do the detailed work required to ensure the PTCID line up with the ATC methodology in the operating horizon (the ATCID)?
Response: The draft standard has been modified to remove any reference to transfer capability calculations for use in ATC calculations in the operational horizon.		

6. The draft standard proposes two new definitions.

Planning Transfer Capability (PTC): A forecast of the Transfer Capability between areas that is used in the Near-Term Planning Horizon and Long-Term Planning Horizon when performing planning analyses.

Planning Transfer Capability Implementation Document (PTCID): A document that describes the implementation of a method for calculating PTC, and provides information related to a Planning Coordinator's calculation of PTC.

Do you agree with the proposed definitions in the draft standard?

Summary Consideration: Some of the commenters indicated that the PTC definition was not needed and was covered by Total Transfer Capability (TTC) and Transfer Capability (TC). The SDT explained that the term (PTC) is needed to avoid any confusion with the terms the commenter identified, TTC and TC. The terms PTC, TTC and TC have different meanings and purposes. The draft standard was not intended to address TTC calculations.

A few commenter's questioned the relationship between FAC-010-2 and FAC-013-2. There is no relationship between FAC-010-2 and FAC-013-2. FAC-010-2 deals with calculation of SOLs and the subset of SOLs that are IROLs, based on specific criteria contained in the standards - while FAC-013-2 requires calculation of PTCs according to the Planning Coordinator's PTCID (now PTCMD in the second draft of the standard), which are based on the PC's own set criteria. PTCs could be calculated between areas where no SOLs have been established; PTCs are calculated to enhance the Planning Coordinator's understanding of the system behavior and not to establish operating limits.

A couple of commenters questioned the use of the phrase "A forecast of the" in the definition of PTC and stated that the planning horizon has not been defined. The SDT agrees with the commenter and modified the definition to now read "The Transfer Capability that is calculated for the planning period (beyond 13 months)."

Another commenter objected to the use of the phrase "implementation of a method" and suggested that the name of the document be changed to Planning Transfer Capability Methodology Document (PTCMD). The SDT agrees and has revised both the name and the definition. The definition of PTCMD now reads "A document that describes the process for calculating Planning Transfer Capability (PTC)."

Planning Transfer Capability (PTC): The Transfer Capability that is calculated for the planning period (beyond 13 months).

Planning Transfer Capability Implementation Document (PTCID): A document that describes the implementation of a method for calculating Planning Transfer Capability (PTC), and provides information related to a Planning Coordinator's calculation of PTC.

Organization	Yes or No	Question 6 Comment
FirstEnergy	No	FE believes that the Planning Transfer Capability definition is not needed as the existing terms for Total Transfer Capability and Transfer Capability should suffice and that it should be well understood that the timeframe for this standard is the planning horizon. We support the PTCID definition with the following conforming change: "A document that describes the implementation of a method for calculating Total Transfer Capability (TTC) for a Planning Horizon and provides information related to a Planning Coordinator's calculation of TTC."
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. **This draft standard is not intended to address TTC calculations.**		
Southern Company Transmission	No	In general, Southern agrees with the proposed definitions of PTC and PTCID; however, Southern would like to propose a revision to the definition of PTC to capture that PTC is the forecast of Transfer Capabilities beyond the 13 month timeframe. The calculations of Transfer Capabilities within the timeframes from 1 hour up to 13 months have been adequately covered by the MOD Reliability Standards approved within FERC's Order 729. Additionally, the term "Planning Horizon" is not a term currently defined in the NERC Glossary. Although FERC implied in Order 729 that the planning horizon is years one through five, Southern recommends that NERC either define the term Planning Horizon or rephrase the definition of PTC to capture the applicable timeframe as specified in FERC Order 729 without referencing the term Planning Horizon.
Response: The SDT agrees and has modified the standard to only require calculation of PTC's beyond 13 months.		
Georgia Transmission Corporation	No	The definition of Planning Transfer Capability is inconsistent with the definitions of ATC in MOD-001-1 and TTC in MOD-028-1, MOD-029-1, and MOD-030-2. ATC and TTC in the MOD standards are calculated for each ATC Path. A more consistent definition would be "A forecast of the transfer capability for each ATC Path that is used in the Planning Horizon when performing planning analyses". GTC notes that Order 729, paragraph 279 states, "The Commission also expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system. The Commission directed the ERO to modify FAC-012-1 to provide a framework for the transfer capability calculation methodology that takes account of the need for consistency in the criteria used to calculate transfer capabilities."
Response: The Planning Coordinator should be afforded the flexibility to include more or fewer paths in their PTCID if they believe it appropriate. **The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.**		

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	No	The definition of Planning Transfer Capability is vague. It is unclear if Planning Transfer Capability is meant to be different than Total Transfer Capability in the Planning Horizon. Is Planning Transfer Capability the same as Total Transfer Capability in the Planning Horizon? If not, how are they different? How does PTC relate to the requirements in FAC-010-2 regarding determination of the System Operating Limit for the Planning Horizon? BPA disagrees with the proposed definition of PTC and does not see the need for this new term.
Response: The PTC is not the same as the TTC. This draft standard is not intended to address TTC calculations. **There is no relationship between the FAC-010 and FAC-013. FAC-010 deals with calculation of SOL and IROL's based on specific criteria contained in the standard. FAC-013 only requires calculation of PTC's according to the Planning Coordinator's PTCID, which is based on their criteria. For instance, PTC may be calculated between areas where no SOL is established. PTC's are calculated to enhance the Planning Coordinators understanding of system behavior not to establish system operating limits.**		
Manitoba Hydro	No	The PTC definition should refer to 'interfaces', not 'areas'. It should align with R1.1.1 which refers to interfaces. The PTC is a transfer capability not a forecast of a transfer capability.Proposed PTC definition: Planning Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions in the planning horizon of one year or longer.The group of lines or paths between adjacent areas comprise an interface.Why is it necessary to have a new definition instead of using the definition of Transfer Capability in the NERC Glossary: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A."The standard could just refer to "Transfer Capability in the planning horizon. Planning horizon should be defined. The PTCID definition is unnecessarily wordy. Also, the PTCID should describe a method not an 'implementation of a method'.Proposed PTCID definition: PTCID: A document that describes the method for calculating PTC.
Response: The SDT has removed the references to "areas" from the definition of PTC. The term "interfaces" has also been removed from what used to be Requirement R1.1.1 (now R1.2) from this draft of the standard and simply requires a list of the PTCs to be calculated. Requirement R1.2 now reads "A list of all Planning Transfer Capabilities (PTC) to be calculated." **The SDT agrees with your comment regarding the phrase "A forecast of the". The SDT has revised the definition and it now reads "The Transfer Capability that is calculated for the planning horizon (beyond 13 months)". This also addresses your concern with defining planning horizon.** **The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.** **The SDT has revised the draft standard to require documentation of their method for calculating PTC.**		

Organization	Yes or No	Question 6 Comment
Xcel Energy	No	There is no need to create the term Planning Transfer Capability (PTC). Transfer Capability is a well understood long standing NERC defined term and should be used in its place. Furthermore, the proposed definition is not consistent with the Transfer Capability or Total Transfer Capability definitions.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. **The SDT has capitalized "Transfer Capability" in the definition to make clear that this is based on the NERC Glossary of Terms and is not Total Transfer Capability, which is a separate term.**		
Independent Electricity System Operator	No	We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been adopted for a long period of time. The industry is familiar with this definition, and have a deep and unambiguous understanding that in general term, it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). We view the proposed definition as redundant since it is similar to the definitions of Transfer Capability and Total Transfer Capability already in the NERC Glossary, viz.:Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A."Total Transfer Capability:The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.If the reason to create this definition is to make a distinction that this is the term used for planning assessment in the context of this standard, then we believe that this can be achieved simply by adding the phrase "in the planning horizon" to the term Transfer Capability. We do not have a difficulty with the creation of the term "Transfer Capability Implementation Document for so long as the word "Planning" is removed.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. The SDT revised the definition of PTC in support of your suggestion and eliminated the language that duplicated the definition of transfer capability. Based on comments from other stakeholders, the definition of PTCID was changed to PTCMD to clarify that the document focuses on the 'methodology' for calculating Planning Transfer Capability rather than 'implementation' of that methodology.		
IRC Standards Review Committee	No	We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been adopted for a long period of time. The industry is familiar with this definition, and have a deep and unambiguous understanding that in general term, it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). The proposed definition is not needed since it quotes transfer capability which is already a defined term in the NERC Glossary, as follows:Transfer Capability: The measure of the ability of

Organization	Yes or No	Question 6 Comment
		interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.”If the reason to create this definition is to make a distinction that this is the term used for planning assessment in the context of this standard, then we believe that this can be achieved simply by adding the phrase “in the planning horizon” to the term Transfer Capability.We do not have a difficulty with the creation of the term “Transfer Capability Implementation Document for so long as the word “Planning” is removed.Note that CAISO does not sign on to this specific comment.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.		
Northeast Power Coordinating Council	No	We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been in use for a long period of time. The industry is familiar with this definition, and has an understanding that it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). The proposed definition is not compatible with either the definition of Transfer Capability or the definition of Total Transfer Capability in the NERC Glossary, as follows:Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.”Total Transfer Capability:The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.If this definition was created to emphasize that this is the term used for planning assessment in the context of this standard, then this could be achieved simply by adding the phrase “in the planning horizon” to the term Transfer Capability. We accept the creation of the term “Transfer Capability Implementation Document". “Planning” should be removed.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.		
Ameren	No	What is the need for PTC? We believe that well established NERC terms like ATC, TTC, FCITC should be used. The proposed definition of PTC is not consistent these terms. Furter, we have several questions with regard to PTC : Is PTC simultaneous or non-simultaneous? How is PTC will be used? Is PC going to decide how it would be used?
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a		

Organization	Yes or No	Question 6 Comment
different meaning and purpose. **The PTCMD allows the Planning Coordinator to tailor the calculation of PTC to its specific reliability objectives.**		
SERC Planning Standards Subcommittee	No	While we agree with the PTC definition we recommend that the phrase "implementation of a method" in the PTCID definition be replaced with the term "methodology" and the name of the document be changed to "Planning Transfer Capability Methodology Document (PTCMD)."
Response: The SDT agrees with your comment and has modified the definition. The definition now reads "A document that describes the process for calculating Planning Transfer Capability (PTC)."		
Midwest ISO Stakeholder Standards Collaborators	No	There is no need to create the term Planning Transfer Capability (PTC). Transfer Capability is a well understood long standing NERC defined term and should be used in its place. Furthermore, the proposed definition is not consistent with the Transfer Capability or Total Transfer Capability definitions.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. The SDT revised the definition of PTC to eliminate the language that duplicated the definition of transfer capability.		
California ISO	Yes	
Duke Energy	Yes	

7. The proposed purpose statement in the draft standard is:

> To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those Transfer Capabilities can be used effectively in the reliable planning of the Bulk Electric System (BES).

Do you agree with this purpose? If not, please identify to whom the standard should apply.

Summary Consideration: Several of the commenters indicated that the term PTC is unnecessary and proposed that PTC could also be replaced in the Purpose Statement with “Transfer Capability in the planning horizon”. The SDT retained the definition of PTC and therefore included the term within the Purpose Statement. The term PTC is necessary to avoid any confusion with other forms of transfer capability (i.e., TTC and ATC) that have different meanings and purposes.

A couple commenters questioned the meaning of the phrase, “. . . used effectively in the reliable planning of the BES.” The SDT modified the Purpose Statement to be more succinct - it now reads “To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES).”

Organization	Yes or No	Question 7 Comment
Bonneville Power Administration	No	It is unclear what the difference is between the purpose statement of the proposed FAC-013-2 and the purpose statements of FAC-010-2 and FAC-014-2. The purpose statements seem to be identical. BPA asks for clarification regarding the need for this proposed standard. For reference the purpose statement of FAC-010-2 reads as follows:”To ensure that System Operating Limits (SOLs) used in the reliable planning ofthe Bulk Electric System (BES) are determined based on an established methodology or methodologies.”The purpose statement of FAC-014-2 reads as follows: “To ensure that System Operation Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.”
Response: There is no relationship between the FAC-010/FAC-14 and FAC-013. FAC-010/FAC-14 deal with calculation and communication of SOLs and IROLs based on specific criteria contained in the standards. FAC-013 only requires calculation of PTCs according to the Planning Coordinator’s PTCID (now called the PTCMD in the second draft of the standard), which is based on the Planning Coordinator’s criteria. For instance, PTCs may be calculated between areas where no SOLs are established. PTCs are calculated to enhance the Planning Coordinator’s understanding of system behavior not to establish system operating limits. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.		
Midwest ISO Stakeholder	No	Planning Transfer Capabilities should be replaced with Transfer Capabilities. As an option, the purpose

Organization	Yes or No	Question 7 Comment
Standards Collaborators		statement could refer to the Transfer Capabilities in the planning horizon.
Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the SDT did revise the definition of PTC – the revised definition eliminates the language that duplicated the definition of transfer capability.		
Xcel Energy	No	Planning Transfer Capability should be replaced with Transfer Capabilities. As an option, the purpose statement could refer to the Transfer Capabilities in the planning horizon.
Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the SDT did revise the definition of PTC – the revised definition eliminates the language that duplicated the definition of transfer capability.		
Ameren	No	Please see our comments to question 6.
Response: Please see the response to your comments on question 6. **The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have different meanings and purposes.** **The PTCMD (previously called the PTCID) allows the Planning Coordinator to tailor the calculation of PTC to its specific reliability objectives.**		
PJM Interconnection	No	Revised purpose statement: To ensure that Planning Coordinators use an established method for effective, reliable planning of the Bulk Electric System (BES). Note: This methodology does not need to involve the calculation of transfer capability in the planning horizon
Response: The SDT believes there is a necessity for the calculation of planning transfer capability beyond 13 months. The SDT also believes that the proposed Purpose statement is too generic.		
Manitoba Hydro	No	The proposed purpose is unclear. What does 'used effectively in the reliable planning of the Bulk Electric System (BES)' mean?The purpose statement should simply be: To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method. Also, if FAC-012-1 and FAC-013-1 are combined, the purpose should include a statement such as "and distribute the PTCs to the entities that have a reliability related requirement for them".
Response: The SDT has reworded the purpose to be more succinct. The purpose statement now reads "To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES)." **There are requirements for distribution of PTC's but the SDT does not believe it is necessary to specifically include it in the purpose statement.**		

Organization	Yes or No	Question 7 Comment
Duke Energy	No	The Purpose should be reworded to clearly state that the objective of this standard is not to simply determine transfer capabilities in the planning timeframe, but to assess the future reliability of the system. Suggested rewording: "To ensure that Planning Coordinators use an established methodology to assess whether sufficient transmission system capacity is available to support reliable operation of the Bulk Power System in the planning horizon."
Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. The draft standard was not intended to address assessments but only address the development of the PCs methodology to calculate PTCs and share these PTCs with the necessary entities.		
Independent Electricity System Operator	No	We do not support the word "Planning" before "Transfer Capabilities" for reasons as indicated under Q6, above. Words such as "Planning Coordinators and "reliable planning" already suffice to put the Transfer Capabilities in the proper time horizon perspective.
Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the team did revise the definition of PTC in support of stakeholder suggestions, and the revised definition eliminates the language that duplicated the definition of transfer capability.		
IRC Standards Review Committee	No	We do not support the word "Planning" before "Transfer Capabilities" for reasons as indicated under Q6, above. Words such as "Planning Coordinators and "reliable planning" already suffice to put the Transfer Capabilities in the proper time horizon perspective.Note that CAISO does not sign on to this specific comment.
Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the team did revise the definition of PTC in support of stakeholder suggestions, and the revised definition eliminates the language that duplicated the definition of transfer capability.		
Northeast Power Coordinating Council	No	We do not support the word "Planning" before "Transfer Capabilities" for reasons as indicated in Question 6 preceding. Words such as "Planning Coordinators" and "reliable planning" suffice to put the Transfer Capabilities in the proper time horizon perspective.
Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the team did revise the definition of PTC in support of stakeholder suggestions, and the revised definition eliminates the language that duplicated		

Organization	Yes or No	Question 7 Comment
the definition of transfer capability.		
Southern Company Transmission	Yes	Southern agrees with NERC's proposed purpose statement in that Transfer Capabilities should be calculated using an established method and used effectively for the reliable planning of the Bulk Electric System. However, Southern does not believe that NERC's proposed FAC-13-2 addresses this purpose statement. Southern does not believe there are currently any established methods for which Transfer Capabilities are calculated beyond the 13 month timeframe. The existing MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2) provide for the calculation of Transfer Capabilities in the operating horizon only (i.e. up to 13 months). FERC's directive in Order 729 was to develop modifications to FAC-12-1 and FAC-13-1 to comply with the relevant directives of Order No. 693, in which, NERC was directed to modify FAC-12-1 to provide a framework for calculating transfer capability. Southern believes NERC has fully addressed this framework in regards to the operating horizon with the MOD Reliability Standards approved within FERC Order 729. As such, Southern recommends that existing reliability standards (i.e. FAC-12-1) be modified or new reliability standards be created to provide a framework for the calculation of Transfer Capabilities beyond 13 months.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has modified the draft standard to provide a framework for the calculation of PTC for the time period beyond 13 months. The SDT has also modified the Purpose Statement to now read "To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES)."		
California ISO	Yes	
FirstEnergy	Yes	
Georgia Transmission Corporation	Yes	

8. The draft standard proposes to merge FAC-012 and FAC-013. Do you agree with this approach? If not, please suggest an alternate approach.

Summary Consideration: One commenter questioned the need for FAC-013-2 and instead proposed modifying FAC-010-2 and FAC-014-2 to cover the necessary requirements. There is no relationship between FAC-010-2/FAC-014-2 and FAC-013. FAC-010-2/FAC-014-2 deal with calculation and communication of SOLs and IROLs based on specific criteria contained in the standards while FAC-013-2 requires calculation of PTCs according to the Planning Coordinator's PTCID (now called the PTCMD in the second draft of the standard), which are based on the PC's own set of criteria. A PTC could be calculated between areas where no SOL has been established - PTCs are calculated to enhance the Planning Coordinator's understanding of the system behavior and not to establish operating limits.

Another commenter stated that they did not disagreement with merging FAC-012 and FAC-013 unless a single method of calculating PTCs beyond 13 months was approved. The SDT does not believe identifying a single method would be appropriate. The draft standard FAC-013-2 provides flexibility for Planning Coordinators to evaluate PTCs based on the needs and behavior of the Planning Coordinator's area of responsibility.

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	BPA proposes to retire FAC-012 and FAC-013 and instead modify FAC-010-2, and FAC-014-2 to respond to FERC's directives in Order 693 and Order 729. This will avoid the appearance of duplication and provide consistency between these standards.
Response: There is no relationship between the FAC-010/FAC-14 and FAC-013. FAC-010/FAC-14 deal with calculation and communication of SOLs and IROLs based on specific criteria contained in the standards. FAC-013 only requires calculation of PTCs according to the Planning Coordinator's PTCID (now called the PTCMD in the second draft of the standard), which is based on the Planning Coordinator's criteria. For instance, a PTC may be calculated between areas where no SOL is established. PTCs are calculated to enhance the Planning Coordinator's understanding of system behavior, not to establish system operating limits. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have different meanings and purposes.		
Manitoba Hydro	No	Manitoba Hydro strongly suggests that the Standard Drafting Team revert back to FAC-012. With some minor modifications to the current FAC-012, a clear and adequate standard could be established. By dropping the reference to the RC in R1 & R4 & M1 & M4 & D, R2 and M2 the current FAC-012 would be applicable only to the PA (not the PA and the RC). Requirement R1 in FAC-012 lists some important items that should be included in a transfer capability methodology. These items are not included in the proposed FAC-013-2 standard. There is nothing in the proposed FAC-013-2 standard that makes it superior to the current FAC-012 standard.

Organization	Yes or No	Question 8 Comment
Response: The SDT believes that the revised standard preserves the important requirements from FAC-012 as you have suggested and also addresses the FERC directives.		
Southern Company Transmission	No	Southern does not support merging FAC-12 and FAC-13 unless a single method for calculating Transfer Capabilities beyond 13 months is approved. FAC-13-1 is a FERC approved standard that requires either the reliability coordinator or the planning authority to calculate transfer capabilities based on an established methodology and provide those transfer capabilities to its transmission operators, transmission service providers and planning authorities within the reliability coordinator's area. In FERC's Order 729, the commission stated that the responsibilities of FAC-12 and FAC-13 would be appropriately assigned to the Planning Coordinator and not the reliability coordinator. FAC-13 is simply a standard by which Transfer Capabilities calculated by a Planning Coordinator should be communicated to the Transmission Operator and Transmission Service Provider. FAC-13 does not prescribe how to calculate these Transfer Capabilities. As previously stated, Southern does not believe that there are established methodologies that provide the framework for calculating Transfer Capabilities beyond 13 months. Southern recommends that either FAC-12 be modified to provide the framework for a single methodology used for calculating Transfer Capabilities beyond 13 months or additional standards be created to provide such frameworks similar to those prescribed in the MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2). Additionally, Southern would not support the modification of MOD-28-1, MOD-29-1, or MOD-30-2 in order to provide this framework beyond 13 months.
Response: The SDT is not saying that there are present methodologies for calculating PTCs beyond 13 months. The purpose of this draft standard is to mandate that PCs develop these methodologies. **The SDT does not believe that identifying a single method would be appropriate. FAC-013 provides flexibility for Planning Coordinators to calculate PTCs based on the needs and behavior of their area of responsibility, but the Planning Coordinator must document the method in its PTCMD.**		
Georgia Transmission Corporation	Yes	While GTC agrees that the draft standard should merge FAC-012 and FAC-013, the SAR's Detailed Description says "This SAR proposes to retire FAC-012-1, and modify FAC-013-1." How will this inconsistency be explained?
Response: The new FAC-013-2 will be a revision of FAC-013-1 which incorporates the necessary elements of FAC-012-1 to develop an effective standard addressing PTCs used in the planning horizon.		
Ameren	Yes	
California ISO	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 8 Comment
FirstEnergy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
Midwest ISO Stakeholder Standards Collaborators	Yes	
Northeast Power Coordinating Council	Yes	
PJM Interconnection	Yes	
SERC Planning Standards Subcommittee	Yes	
Xcel Energy	Yes	

9. Does the draft standard adequately address the applicable FERC directives (located in the SAR)? If not, please identify what else is needed.

Summary Consideration: Several of the commenters did not feel that the draft standard addressed FERC concerns with data input and modeling assumptions. The SDT modified the draft standard (Requirement R1) to provide a framework for the PTC methodology including data inputs and modeling assumptions.

A couple of the commenters indicated that Requirements R2 and R3 should be merged. The SDT agreed and merged the requirements.

A few of the commenters indicated that the draft standard as written could preclude some entities access to the PTCs. The SDT modified the draft standard to allow any entity with a reliability related need access to the PTCMD (previously called the PTCID) and PTCs.

Organization	Yes or No	Question 9 Comment
IRC Standards Review Committee	No	(1) Requirement R1 stipulates the information that must be provided in the TCID for planning, and identifies the need to explain and justify any differences in the method used that are not consistent with the method selected by the Transmission Operator and described in the associated Transmission Service Provider's Available Transfer Capability Implementation Document (ATCID). We support this requirement but do not think that the requirement as written is sufficient to address the FERC's concerns that:"....FAC-012-1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions".We understand the Requirement R1 is written to achieve consistency with the pertinent MOD standard (MOD-028 or MOD-029), but it is not clear to us that in the two related standards, the conditions stipulated in the FERC Order in terms of data input and modeling assumption are fully met. We suggest the SDT to review both the draft FAC-013 and the approved MOD standards to ascertain that the FERC's concerns are fully addressed. (2) We suggest R2 and R3 be combined by "Each Planning Coordinator shall make available its current [P]TCID to all of the following entities, and notify these entities before implementing a new or revised [P]TCID. (The [P] indicates our proposal to remove the word "Planning" for the two terms.) (3) We believe the Transmission Planner should be added to Part 2.1. (4) R5 as written may prohibit some entities that have a reliability-related need to obtain the calculated Transfer Capabilities, for example, the Reliability Coordinators. Also, the TCID need-to-know entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, with consideration of including the RCs in the list.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td colspan="3">Response: The SDT has modified the standard (Requirement R1) to provide a framework for the PTC methodology including data inputs and modeling assumptions to address FERC concerns.
The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in this revised version. Note that the SDT did not remove the word “Planning” as proposed. For consistency, the word was retained in the definition of PTC, PTCID (now called PTCMD in the second draft of the standard), and in the requirements to maintain clarity between transfer capability used in this standard and the various forms of transfer capability (ATC, TTC) used in other standards.
The Transmission Planner was included in the Requirement 2 (Part 2.4) and is still included in Part 2.2 in the second version of the proposed standard.
The standard has been modified to allow those entities with a reliability-related need access to the PTCMD and PTC’s – this would include RCs</td></tr>
<tr><td>Independent Electricity System Operator</td><td>No</td><td>(1) We suggest R2 and R3 be combined by “Each Planning Coordinator shall make available its current PTCID to all of the following entities, and notify these entities before implementing a new or revised TCID:
(2) We believe the Transmission Planner should be added to Part 2.1.
(3) R5 as written may preclude some entities that have a reliability-related need to obtain the calculated Transfer Capabilities from receiving them, for example, the Reliability Coordinators. Also, the TCID need-to-now entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, with consideration of including the RCs in the list.</td></tr>
<tr><td colspan="3">Response: The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in the second version of the proposed standard.
The Transmission Planner was included in the Requirement R2 (Part 2.4) and is still included in the second draft of the proposed standard. (Requirement R2, Part 2.2)
The standard has been modified to allow those entities with a reliability-related need access to the PTCMD and PTC’s – this would include RCs.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>(1) We suggest R2 and R3 be combined by “Each Planning Coordinator shall make available its current TCID to all of the following entities, and notify these entities before implementing a new or revised TCID: ...
(2) Transmission Planner should be added to Part 2.1.
(3) R5 as written may prohibit some entities that have a reliability-related need to obtain the calculated Transfer Capabilities, for example, the Reliability Coordinators. Also, the TCID need-to-know entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, and include RC in the list.</td></tr>
<tr><td colspan="3">Response The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in the second version of the proposed standard.
The Transmission Planner was included in the Requirement (R2.4) and is still included in this revised version of the proposed standard.
The standard has been modified to allow those entities with a reliability-related need access to the PTCMD and PTC’s – this would include RCs.</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
Southern Company Transmission	No	In FERC Order 693, the commission directed NERC to modify FAC-12 to, at a minimum, provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. Southern believes that this directive has been fully addressed for the timeframe of 1 hour through 13 months with the MOD Reliability Standards approved within FERC Order 729. The commission stated in FERC Order 729 that calculation of transfer capabilities for the planning horizon (years one through five) had not been addressed by the MOD Reliability Standards and gave additional directives that FAC-12 and FAC-13 be modified to comply with the original directives of FERC Order 693. The primary requirements of the draft standard require the Planning Coordinator to: 1) define the interfaces in which Transfer Capabilities are calculated, 2) explain why the method used to calculate these Transfer Capabilities differ from the method selected by the Transmission Operator in Transmission Service Provider's ATCID, and 3) share the calculated Transfer Capabilities with specified entities. However, the draft standard does not provide the framework for how the Transfer Capabilities should be calculated; and, as previously stated, Southern does not believe that there are established methodologies that provide the framework for calculating Transfer Capabilities beyond 13 months. Therefore, Southern contends that the draft standard does not meet the directive of providing the framework for calculating Transfer Capabilities beyond 13 months.
Response: The SDT has modified the standard to provide a framework for the PTC methodology including data inputs and modeling assumptions to address FERC concerns – see revised Requirement R1.		
Manitoba Hydro	No	In order 729 point 279 the following is stated: 'The Commission expressed concern the FAC-012-1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions.'Where in the draft standard is it required that the PTCID provide data inputs and modeling assumptions?
Response: The SDT has modified the standard to provide a framework for the PTC methodology including data inputs and modeling assumptions to address FERC concerns. Requirement R1 establishes the framework.		
California ISO	No	In support of the SRC comments related to question 9, we suggest the SDT to review both the draft FAC-013-2 and the approved MOD Standards (i.e., MOD-028 or MOD-029) to ascertain that FERC's concerns regarding data input and modeling assumptions are fully addressed. We also support the SRC comment to include the RC in R5.
Response: SDT has added data and modeling details to Requirement R1 to establish a framework and consistency for the PTC methodology. **The RC has access to the information under Requirement R6 by demonstrating a reliability related need.**		

Organization	Yes or No	Question 9 Comment
Ameren	No	Please see our response to question 1.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
FirstEnergy	No	The draft standard does not appear to include a requirement “that the criteria used to calculate planning capabilities for use in planning be identical to the criteria used to calculate available transfer capability and to operate the system.”
Response: The standard has been revised and Requirement R1 Part 1.4 now specifies that this criteria must be included.		
Midwest ISO Stakeholder Standards Collaborators	No	The draft standard does not provide much detail around the data inputs and modeling assumptions requirements that Order 693 directed.
Response: The SDT has added data and modeling details to Requirement R1 to establish a framework and consistency for the PTC methodology.		
Xcel Energy	No	The draft standard does not provide much detail around the data inputs and modeling assumptions requirements that Order 693 directed.
Response: The SDT has added data and modeling details to Requirement R1 to establish a framework and consistency for the PTC methodology.		
SERC Planning Standards Subcommittee	No	The SAR goes beyond what was identified as “concerns” by FERC, see response to Question 1.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Duke Energy	Yes	
Georgia Transmission Corporation	Yes	

10. Do you agree with the measures in the standard (section C)? If not, please state specific reasons why not.

Summary Consideration: Several of the commenters indicated that Requirement R4 and Measure M4 were not properly aligned. The SDT reviewed and modified all of the Requirements and Measures ensuring the proper alignment.

A few commenters indicated that the draft standard was too prescriptive concerning the periods/seasons to be studied. The SDT modified the prescriptive language from M4 related to periods/seasons. The revised draft standard affords the Planning Coordinator the flexibility to determine the period/seasons to be studied.

Organization	Yes or No	Question 10 Comment
IRC Standards Review Committee	No	(1) M4 conveys different evidence requirements than the what R4 requires. R4 asks for annual verification of each of the four seasons' Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but for once every 3 months. They are very different that what's stipulated in the requirement. We suggest M4 be revised to:"Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year.Note that CAISO does not sign on to this specific comment. CAISO is concerned that the Requirement R4 is excessive. Requiring the PC to conduct planning assessments for the Summer and Winter seasons for each calendar year from years two through five, as in current practice across the continent, would suffice. Regardless, there is an inconsistency between Requirement R4 and Measure M4. (2) Some Measure may need to be revised depending on the SDT's response to our comments under Q9.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.**		
Independent Electricity System Operator	No	(1) M4 conveys different evidence requirements than what R4 requires. R4 asks for annual verification of each of the four seasons' Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but for once every 3 months. They are very different that what's stipulated in the requirement. We suggest M4 be revised to:"Each Planning Coordinator shall have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year.

Organization	Yes or No	Question 10 Comment
		(2) Some Measure may need to be revised depending on the SDT's response to our comments under Q9.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.		
Northeast Power Coordinating Council	No	(1) M4 conveys different evidence requirements than what R4 requires. R4 asks for annual verification of each of the four seasons' Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but once every 3 months. They are very different from what's stipulated in the requirement. We suggest M4 be revised to:"Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year. (2) Some Measures may need to be revised depending on the SDT's response to our comments to Question 9.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.		
Bonneville Power Administration	No	Comment #1: R4 does not line up with M4. R4 requires PTCs for spring, summer, fall, and winter while M4 only requires PTCs for each winter and summer. Also R4 requires PTCs to be verified and recalculated, if necessary, at least once each calendar year while M4 requires verification and recalculation of PTCs, if necessary, every three months. These are inconsistent. o BPA proposes the following modification to R4: "Each Planning Coordinator shall verify, and if necessary, recalculate PTCs consistent with its PTCID at least once a year for at least the most limiting season (spring, summer, fall, or winter) for years two through five." o BPA proposes the following language for M4: "Each Planning Coordinator have evidence that it verified, and if necessary, recalculated, its PTCs consistent with its PTCID at least once a year for the most limiting season (spring, summer, fall, or winter) for years two through five." Comment #2: R5 does not line up with M5. R5 requires the Planning Coordinator to make available PTC values to the entities listed, while M4 requires Planning Coordinators to make available the PTCID to those

Organization	Yes or No	Question 10 Comment
		entities. The VSL indicates the Planning Coordinator makes available the PTCs. Is this correct?
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT agrees that the Measure M5 should reference PTC's and not PTCMD. This has been corrected.** **The standard has been modified to allow those entities with a reliability-related need access to the PTCMD and PTCs. The VSLs have been modified to be consistent with the modified requirements.**		
California ISO	No	M4 conveys different evidence requirements compared to what R4 requires. We suggest that R4 and M4 provide some flexibility to the Planning Coordinator to study and verify the conditions that are appropriate for the study area, rather than to require for all four seasons. For example, a peak and off-peak study in R4 may be appropriate for a study area. Similar flexibility in the language should be included in M4.Suggested wording for M4 would be: "Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its PTCs consistent with its PTCID for relevant study scenarios as appropriate for the study area."
Response: The SDT believes that the modifications made to the Requirements and Measures in this version of the draft standard affords the flexibility you have requested. References to specific seasons were omitted from both Requirement R4 and the Measure M4.		
Manitoba Hydro	No	M4: This measure should only require the PC have evidence that it verified , and if necessary recalculated, its PTCs consistent with its PTCID for each winter and summer season for years two through five at least once a year. In R4 is it stated '...at least once each calendar year.'. M5: PTCID should be changed to PTCs. Also, since the PC's PTCs are in the Planning Horizon, there is no need to make them available within a time frame as short as ten calendar days. One month would be a more appropriate time frame.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with each other and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.** **The reference to PTCID in Measure M5 has been changed to PTCs.** **The SDT has modified the Requirement to allow for thirty days.**		
Ameren	No	Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter. Do we need spring and fall PTC (R4)

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 10 Comment</th></tr>
<tr><td></td><td></td><td>when the vales more appropriate for planning would be summer and winter as included in M4.</td></tr>
<tr><td colspan="3">Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency.
The Requirements and Measures have been modified to afford the Planning Coordinator the flexibility to determine the seasons to be studied.</td></tr>
<tr><td>Midwest ISO Stakeholder Standards Collaborators</td><td>No</td><td>Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter.</td></tr>
<tr><td colspan="3">Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency.
The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.</td></tr>
<tr><td>Georgia Transmission Corporation</td><td>No</td><td>Requirement 4 of the draft standard states, “Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year.” However, Measurement 4 states, “Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its PTCs consistent with its PTCID for each winter and summer season for years two through five at least once every three months.” Why is the measurement for each winter and summer season when Requirement 4 specified PTCs for spring, summer, fall, and winter?</td></tr>
<tr><td colspan="3">Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure.
The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>Requirement R4 is much too prescriptive and we propose changes to it in our response to Question # 13 below. Measure M4 should be revised to match the revised requirement. Likewise Requirement R5 has far too tight a timeframe to communicate verified or recalculated transfer capabilities. Since these transfer capabilities are years in the future, 45 days should be allowed to communicate them instead of 10 days.</td></tr>
<tr><td colspan="3">Response: The SDT has modified Measure M4 to better align with R4 and to provide consistency References to specific seasons were omitted from both the requirement and the measure.
The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.
The SDT believes that the modifications made to the Requirements and Measures in this version of the draft standard affords the flexibility you have requested. The team did modify R5 to add more time, but changed the due date from 10 calendar days to 30 calendar days.</td></tr>
</table>

Organization	Yes or No	Question 10 Comment
Southern Company Transmission	No	Southern disagrees with measure M4 in that verification, or possible recalculation of PTCs, should be performed any more frequent than once a year. Southern does not believe that there is a reliability need to calculate PTCs on a quarterly basis for PTCs to be utilized beyond the 13 month horizon. Additionally, Southern does not believe there is a reliability need to calculate seasonal PTCs; and therefore, disagrees that each winter and summer season for years two through five should be verified, or recalculated at least once every three months.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.**		
FirstEnergy	No	The measures will need to be adjusted for the suggested changes in our response to item 9 above.
Response: The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.		
SERC Planning Standards Subcommittee	No	We agree with the MISO comment that Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency.		
Xcel Energy	No	We believe it is premature to establish and review measures until the refinement of requirements is closer to completion
Response: The SDT thanks you for your clarifying comment.		

11. Do you agree with the compliance elements in the standard (Violation Risk Factors, Time Horizons, Violation Severity Levels, and the remainder of section D)? If not, please state specific reasons why not.

Summary Consideration: Several of the commenters felt that the retention period for Requirements R2 and R3 may not be sufficient and that these requirements should be combined as suggested earlier. The SDT merged the two Requirements into one Requirement and agrees with the comment concerning the retention period. The SDT modified the retention period, changed the retention for the revised R2 to require retention of evidence since the last audit to correct any deficiency.

Several commenters also questioned the VRF level set for the Requirements. The SDT reviewed all of the VRFs associated with the Requirements and adjusted them accordingly, lowering two of the VRFs from a "Medium" VRF to a "Lower" VRF level.

Many commenters indicated that the VSLs should have more than one level for determining non-compliance. The SDT agrees in concept with the commenters and modified all of the VSLs in the new draft of the draft standard.

A couple of commenters indicated that there should only be one VSL for Requirement R3 and Requirement R5. The SDT disagrees with the commenters and added more gradated VSLs. Since the requirements apply in a planning timeframe, there should be an allowance for being late with notifications.

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council	No	(1) The retention period for R2 and R3 (or combined as suggested in Question 9) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: The wording for Lower can be interpreted to mean that the responsible entity did not comply with the requirement even if it notified all entities before implementing a new TCID. We suggest to reword it to:"The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified TCID, but was late by up to 30 calendar days after its implementation." (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows:Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late more than 30 calendar days after the 10 calendar day target.High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target.Severe: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the

Organization	Yes or No	Question 11 Comment
		condition “within 10 calendar days” at the end of each VSL. For example, the Lower VSL will read:”The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days.” (4) Some of the VSLs may need to be revised depending on the SDT’s response to our comments to Question 9.
Response: 1) The SDT agrees with your comment and has modified the draft standard to indicate that the evidence for the combined R2/R3 must be retained from the last audit. **2) The SDT agrees with your comment regarding the Lower VSL for Requirement R2 and has modified the wording in the second draft of the proposed standard.** **3) & 4) The SDT agrees with your comment in concept and has modified the VSLs.**		
Independent Electricity System Operator	No	(1) The retention period for R2 and R3 (or to be combined as we suggest) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: For the Lower VSL we suggest the following alternative wording to avoid any possible misinterpretation:”The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID, but was late by up to 30 calendar days after its implementation. (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows:Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late more than 30 calendar days after the 10 calendar day target.High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the condition “within 10 calendar days” at the end of each of the VSL. For example, the Lower VSL will read:”The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days.” (4) Some of the VSLs may need to be revised depending on the SDT’s response to our comments under Q9.
Response: 1) The SDT agrees with your comment and has modified draft standard to indicate that the evidence for the combined R2/R3 must be retained from the last audit.		

Organization	Yes or No	Question 11 Comment
2) The SDT agrees with your comment regarding the Lower VSL for Requirement R2 and has modified the wording in the second draft of the proposed standard. **3) & 4) The SDT agrees with your comment and has modified the VSLs.**		
IRC Standards Review Committee	No	(1) The retention period for R2 and R3 (or to be combined as we suggest) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: The wording for Lower can be interpreted to mean that the responsible entity did not comply with the requirement even if it notified all entities before implementing a new TCID. We suggest to reword it to:"The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID, but was late by up to 30 calendar days after its implementation. (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows:Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late more than 30 calendar days after the 10 calendar day target.High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the condition "within 10 calendar days" at the end of each of the VSL. For example, the Lower VSL will read:"The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days." (4) Some of the VSLs may need to be revised depending on the SDT's response to our comments under Q9.
Response: 1) The SDT agrees with your comment and has modified draft standard to indicate that the evidence for the combined R2/R3 must be retained from the last audit. **2) The SDT agrees with your comment regarding the Lower VSL for Requirement R2 and has modified the wording in the second version of the proposed standard.** **3) & 4) The SDT agrees with your comment and has modified the VSLs.**		
Bonneville Power Administration	No	Comment #1: The 1.4 Data Retention requirement mandates that the Planning Coordinator maintain its current ATCID. Was the intent for the Planning Coordinator to maintain its current PTCID? Comment #2: The risk to reliability from not complying with this standard is very low as it addresses the Planning horizon. A severe Violation Severity Level is too high for these standards.

Organization	Yes or No	Question 11 Comment
		Comment #3: BPA proposes the following changes for the VSL's for R1: o Lower VSL: The Planning Coordinator has a PTCID that does not incorporate changes made up to six months ago. o The wording used for High VSL should replace the wording for Moderate VSL. o The wording used for Severe VSL should replace the wording for High VSL. Comment #4: BPA proposes the following changes to R2: o Lower VSL: The Planning Coordinator failed to notify one or more parties specified in R2 of a new or modified PTCID after, but no more than 45 days after its implementation. o Moderate VSL: The Planning Coordinator failed to notify one or more parties specified in R2 of a new or modified PTCID more than 45, but no more than 90 calendar days after its implementation. o High VSL: The Planning Coordinator failed to notify one or more of the parties specified in R2 of a new or modified PTCID more than 90 calendar days following its implementation. Comment #5: BPA proposes that there should be only one VSL for R3 and it should read as follows: o High VSL: The Planning Coordinator failed to make its PTCID available to one of more of the entities described in R3. Comment #6: BPA proposes that there should be only one VSL for R5 and it should read as follows: o High VSL: The Planning Coordinator failed to make the PTCs available to one or more of the entities described in R5, Part 5.2.
Response: 1) The typo in the Data Retention section has been corrected. **2) The SDT agrees with your comment and has set the VRFs to "Lower" in this version of the draft standard.** **3) The SDT has modified the VSLs for Requirement R1 to better reflect the original and revised Requirement R1.** **4) The SDT agrees in concept with your comment concerning the VSLs for Requirement R2 and has modified the VSLs.** **5 & 6) The SDT disagrees and has actually added VSLs. The SDT felt that since this is in the planning timeframe there should be an allowance for being late with notification.**		
Georgia Transmission Corporation	No	R1 and R4 are listed as having Medium Violation Risk Factors. R1 is a documentation requirement; R4 requires calculations 13 months before real time. These requirements should have Lower Violation Risk Factors.
Response: The SDT agrees with your comment and has modified the second version of the draft standard to reflect "Lower" VRF's.		

Organization	Yes or No	Question 11 Comment
SERC Planning Standards Subcommittee	No	R1 and R4 should have a VRF of "Lower". Calculation of PTCs will not directly lead to BES risk. The second alternative for High VSL for R1 should be graduated from Lower to Severe.
Response: The SDT agrees with your comment and has modified the second version of the draft standard to reflect "Lower" VRF's.		
Duke Energy	No	Requirement R1 should be a Lower VRF, since it's a documentation requirement. Also, VSLs should be revised consistent with proposed changes to the requirements.
Response: The SDT agrees with your comment and has modified the second version of the draft standard to reflect "Lower" VRF's. **The SDT ahs reviewed all of the VSL's and modified them as necessary to be consistent with revisions to the requirements.**		
Manitoba Hydro	No	The Violation Risk Factors should all be Lower. The Time Horizons are all Planning and as such violating any of the Requirements in this proposed standard will not result in anything more than a low level of risk.Violation Severity Levels:R1: The VSLs refer to times of three months/six months/not more than one year/a year or more whereas Requirement R1 does not refer to any time periods.R2: The VSLs refer to times of 30 calendar days/31-60 calendar days/61-90 calendar days/more than 90 calendar days whereas Requirement R2 does not refer to any time periods.R3: The VSLs are not properly allocated for a binary VSL Requirement.R5: The VSLs do not mention any time periods whereas Requirement R5 states '...no later than ten calendar days...'.
Response: The SDT agrees with your comment and has modified the second version of the draft standard to reflect "Lower" VRF's. **Requirements R1 & R2) The SDT has modified the VSLs to better align with the intent of the requirement taking into account time periods when necessary.** **Requirement R3) The SDT has merged the old Requirement R2 and Requirement R3 together and the VSLs have been modified accordingly.** **Requirement R5) The SDT agrees with your comment and has modified the VSL accordingly.**		
California ISO	No	We request consideration be given to extend the "no later than 10 calendar days" time allowed in R5 and the VSLs for R5 to "no later than 15 calendar days." We suggest the following for R5 VSLs:Lower VSL: The Planning Coordinator made the PTCs available to one or more of the entities described in R5, Part 5.2, after 15 calendar days.Moderate VSL: The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.2, within 15 calendar days.High VSL: The Planning Coordinator made the PTCs available to one or more of the entities described in R5, Part 5.1, after 15 calendar days.Severe VSL: The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.1 within 15 calendar days.
Response: The SDT agrees with your comment and has modified the draft standard to reflect 30 calendar days **The VSLs have been modified based on calendar days. The SDT feels that notification is extremely important but also believes there should be some**		

Organization	Yes or No	Question 11 Comment
allowance for late notification.		
FirstEnergy	Yes	
Southern Company Transmission	Yes	

12. Are you aware of any conflicts between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Summary Consideration: There was only one comment and this was a repeat of an earlier comment.

Organization	Yes or No	Question 12 Comment
California ISO	No	
Duke Energy	No	
FirstEnergy	No	
Georgia Transmission Corporation	No	
IRC Standards Review Committee	No	
Manitoba Hydro	No	
SERC Planning Standards Subcommittee	No	
Southern Company Transmission	No	
PJM Interconnection	Yes	See answers to questions 4 and 5
Response: See response to Question 4 and Question 5.		

13. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standard.

Summary Consideration: A couple of commenters indicated that the draft standard was too prescriptive as to the frequency of the studies. The SDT agreed with the commenter and modified the requirement to now read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD (formerly called the PTCID) for years two through five at least once each year."

A few of the commenters stated that 10 days was not sufficient time for making PTCs available. The SDT agreed with the commenter and modified the draft standard to allow for 30 calendar days.

A couple of commenters indicated that PTCs should be made available to certain entities without being asked. The SDT agreed with the commenter and modified the draft standard to reflect the suggested change.

A couple of the commenters indicated the standard was unclear as to the paths that needed to be studied for PTC calculations. The SDT explained that the Planning Coordinator should be afforded the flexibility to include more or fewer paths as well as define the paths in its PTCMD (formerly called PTCID) if they believe that it is appropriate.

Another commenter indicated that the standard should require coordination of interfaces for the calculation of PTC with other PC's. The SDT explained that requirement to share the information with other entities allowed the entities to review the information and therefore was sufficient coordination.

Organization	Yes or No	Question 13 Comment
Ameren		(1) In R5, PTC should be available to all the entities in R2 without being asked. TOP will be more interested in changes in PTC than changes in PTCID. (2) It is unclesr if PTC to be calculated between TOP areas, or from BA to BA, region to region, or sub-region to sub-refion? The document should require PC to work with TP and TOP to identify necessary interfaces to calculate transfer capabilities for Planning horizon. (3) PTC should be referred to as an acronym in R1.1 when it is used first time as the acronym was used then in R4.
Response: 1) The SDT agrees and has modified this version of the draft standard to reflect your suggestion to make the document available to any entity with a reliability-related need for the information. **2) The SDT believes the Planning Coordinator should be afforded the flexibility to include more or fewer paths in its PTCMD if it believes it appropriate. The requirement to share the PTCMD and the requirement to respond to comments received will afford appropriate input.** **3) The SDT agrees and this version of the draft standard reflects your suggested modification.**		

Organization	Yes or No	Question 13 Comment
Manitoba Hydro		Manitoba Hydro strongly suggests that the Standard Drafting Team refer back to FAC-012. With some minor modifications to the current FAC-012, a clear and adequate standard could be established. By dropping 4.1, the reference to the RC in R1 & R4 & M1 & M4 & D, R2 and M2 the current FAC-012 would be applicable only to the PA (not the PA and the RC). Requirement R1 in FAC-012 lists some important items that should be included in a transfer capability methodology. These items are not included in the proposed FAC-013-2 standard. There is nothing in the proposed FAC-013-2 standard that makes it superior to the current FAC-012 standard.Referring to the proposed FAC-013-2 Standard, R4 requires the PC to complete many detailed studies and verifications. This is unnecessary work in determining planning horizon PTCs. R4 should be changed to 'Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCID for the Summer and Winter seasons for years two and five at least once each calendar year.' Spring and Fall models are not currently created in the Planning Horizon. Requiring the PC to model and analyze Spring and Fall models in the Planning Horizon seems to be market driven, rather than reliability driven.There are is no requirement that the PCs on either side of an 'interface' coordinate when determining PTCs for the 'interface'. The Effective Date cannot be dependent on another standards' effective date (ie. cannot be dependent are the date that MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective).
Response: The revised standard preserves the important requirements from FAC-012 as suggested. **The SDT agrees with your concerns about scope of work and has modified the requirement to read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year, with no more than 15 months between verifications."** **The SDT believes that sharing the information with the PCs is sufficient coordination as required in the new R2 and R5. FERC has recognized that even in ATC calculations ATC values will not be identical on either side of the interface(s).** **The effective date has been established through FERC Order and is beyond the SDT's control.**		
Georgia Transmission Corporation		Requirement 1.1.1 of the draft standard states, "A list of the interfaces for which the Planning Coordinator determines a Planning Transfer Capability". GTC believes this should be ""A list of ATC Paths for which the Planning Coordinator determines a Planning Transfer Capability." This would be consistent with the definitions of ATC in MOD-001-1 and TTC in MOD-028-1, MOD-029-1, and MOD-030-2. ATC and TTC in the MOD standards are calculated for each ATC Path. Order 729, paragraph 291 states, "In making these revisions, the ERO should consider the development of a methodology for calculation of inter-regional and intra-regional transfer capabilities". Will this FERC request be considered? If so, please identify the part of the draft standard that addresses it.
Response: The SDT believes that Requirement R1 will provide the needed framework for evaluating transfer capability beyond 13 months while ensuring that the Planning Coordinator's need for flexibility is met. The phrase, "A list of the interfaces for which the Planning Coordinator determines a Planning Transfer Capability" was removed from the second draft of the proposed standard.		

Organization	Yes or No	Question 13 Comment
California ISO		We suggest that R4 and M4 provide some flexibility to the Planning Coordinator to evaluate the conditions that are appropriate for the study area, rather than to require all four seasons be evaluated. For example, a peak and off-peak study in R4 may be appropriate for a study area. For R4, where it specifies for years two through five, we request that the SDT consider years two and five, similar to the proposed Requirement 2.1.1 in Draft 5 of the TPL-001-1 Standard that is under development in NERC Project 2006-02. For R5, we ask the SDT to give consideration to extending the timeframe allowed beyond 10 calendar days to 15 calendar days.
Response: The SDT has removed the requirement to study all four seasons and modified the requirement to now read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year, with no more than 15 months between verifications." The SDT feels that studying years 2 through 5 is appropriate. **Requirement R5 has been modified to allow 30 calendar days for making PTCs available.**		
FirstEnergy	Yes	Each requirement shows a time horizon of "Planning", however, this is not a defined horizon. There are two types of planning horizons defined by NERC, "Long-Term Planning" and "Operations Planning". The SDT should clarify the intent is Long-Term Planning.
Response: The definition of PTC clarifies that the time period is beyond 13 months. The time horizons are defined, and the definition of the "Long-Term Planning" time horizon is "a planning horizon of one year or longer"		
Midwest ISO Stakeholder Standards Collaborators	Yes	It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on.R2 and R3 should be combined into a single requirement. R2 in essence requires pre-notification of coming changes to the PTCID but there is no need to specify what the changes are. Then R3 requires notification again to the same entities with an actual copy of the changes. R2 as written is an administrative requirement that provides no reliability benefit.Resource Planners should receive copies of the Transfer Capabilities in R5 as well. They need to know their import capabilities in order to determine if they have access to sufficient generation to cover their load.
Response: The SDT believes the Planning Coordinator should be afforded the flexibility to include more or fewer paths in its PTCMD if it believes it appropriate. **The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in this second draft of the proposed standard.** **Resource Planners with a reliability related need, will be able to request PTC data.**		
Xcel Energy	Yes	It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should

Organization	Yes or No	Question 13 Comment
		simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on.
Response: The SDT believes the Planning Coordinator should be afforded the flexibility to include more or fewer paths in its PTCMD if it believes it appropriate		
Duke Energy	Yes	o Delete Requirements R2.2 and R2.3 because TSPs and TOPs really have no need of the PTCID. o Requirement R4 specifies a frequency that is overly prescriptive/granular and unnecessary for assessments in the planning timeframe. Suggested rewording: “Consistent with its PTCID, each Planning Coordinator shall assess PTCs in the near-term planning horizon and the long-term planning horizon at least once every two years.” o Change the time in Requirement R5 from 10 days to 45 days, since this is a planning timeframe requirement. o Reword Requirement R5.2 to indicate that any other registered entities (not just those specified in R2) that have a reliability-related need can make a written request and receive the PTCs. o Add a new Requirement R5.3 as follows: “Each Planning Coordinator adjacent to the Planning Coordinator’s planning coordinator area.” o Under Data Retention, there is a typo in the second bullet: ATCID should be PTCID.
Response: The SDT agrees TSPs and TOPs do not have a reliability related need and has dropped them from Requirement R2. **The SDT has removed the requirement to study all four seasons and modified the requirement to now read “Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year, with no more than 15 months between verifications.” The SDT feels that studying years 2 through 5 is appropriate.”** **Requirement R5 has been modified to allow 30 calendar days for making PTCs available.** **The SDT agrees and has modified Requirement R5, Part5.2 (now Requirement R5) to reflect your suggested modification to allow those with a reliability-related need access to PTCs as well as adjacent Planning Coordinators.** **Under Data Retention, the typo in the first bullet has been corrected to refer to PTCMD.**		
Southern Company Transmission	Yes	Southern disagrees with requirement R1.1.2 in that a Planning Coordinator should have to provide a detailed explanation as to why the methods used to calculate PTCs are or are not different from those methods selected by the Transmission Operator as described in the Transmission Service Providers ATCID. The methods selected by the Transmission Operator in the ATCID do not provide the framework to calculate Transfer Capabilities beyond 13 months. Additionally, Southern disagrees with requirement R.1.1.3 to provide a justification as to why a method identified in a Planning Coordinator’s PTCID is inconsistent with the Transmission Service Provider’s ATCID.

Organization	Yes or No	Question 13 Comment
		The existing, FERC approved MOD-001-1 allows for a path of which ATC is calculated to utilize different methodologies for different timeframes. For example, a Transmission Service Provider could select MOD-28-1 (Area Interchange) to utilize when calculating Transfer Capabilities for use in Hourly ATC calculations and select MOD-29-1 (Rated System Path) to utilize when calculating Transfer Capabilities for use in Monthly ATC calculations without requiring any justification for why the Transmission Service Provider chose to select different methods for the different timeframes. As such, Southern does not agree with any requirement to justify why a Planning Coordinator chose a different method for calculating Transfer Capabilities beyond 13 months. Southern disagrees with requirement R4 in that the calculation of seasonal transfer capabilities should be calculated for years two through five. Southern does not believe that there is a reliability need for Planning Coordinators to calculate seasonal PTCs. Each Planning Coordinator determines the most critical system condition for their respective area and performs reliability evaluations on these critical system conditions when creating their reliability expansion plan. Therefore, each Planning Coordinator should not be required to calculate seasonal PTCs for a timeframes that haven't been defined as a critical system condition for their area. Southern recommends that yearly Transfer Capabilities should be the only Transfer Capabilities calculated beyond 13 months through five years and that these Transfer Capabilities be calculated no more than annually.
Response: The SDT has removed Requirement R1, Parts 1.1.2 and 1.1.3. **The SDT has removed the requirement to study all four seasons and modified the requirement to now read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year, with no more than 15 months between verifications." The SDT feels that studying years 2 through 5 is appropriate.**		
SERC Planning Standards Subcommittee	Yes	We recommend that part 5.2 under R5 be restated as: "Any other entities that demonstrate that they have a reliability-related need for such PTCs and make a written request for such PTCs." We recommend that part 1.1 under R1 be restated as: "A list of all Transmission Operators for which the Planning Coordinator determines Planning Transfer Capabilities. Include the following for each of these Transmission Operators." In the first bullet under D.1.4, change "ATCID" to "PTCID." We agree with the MISO comments that: 1) It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on. 2) R2 and R3 should be combined into a single requirement. R2 in essence requires pre-notification of coming changes to the PTCID but there is no need to specify what the changes are. Then R3 requires

Organization	Yes or No	Question 13 Comment
		notification again to the same entities with an actual copy of the changes. R2 as written is an administrative requirement that provides no reliability benefit. The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.

Response: The SDT has modified Requirement R5 to allow those entities with a reliability related need to have access to PTCs.

The SDT has revised Requirement R1, Part 1.1 and the SDT believes that this revision accomplishes your suggested change.

Under Data Retention, the typo in the first bullet has been corrected to refer to PTCMD.

The SDT believes the Planning Coordinator should be afforded the flexibility to include more or fewer paths in its PTCMD if it believes it appropriate.

The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in this second draft of the proposed standard.