NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Modifications to FAC-012 and FAC-013 for Order 729 Draft FAC-013-2 Standard — Project 2010-10

The Modifications to FAC-012 and FAC-013 for Order 729 - Draft FAC-013-2 Standard Drafting Team thanks all commenters who submitted comments on the SAR and modifications proposed FAC-013-2 — Planning Transfer Capability. These standards were posted for a 45-day public comment period from September 20, 2010 through November 3, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 33 sets of comments, including comments from more than 98 different people from approximately 75 companies representing 10 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:

- Removed the definitions of Planning Transfer Capability (PTC) and Planning Transfer Capability Methodology Document (PTCMD).
- Modified the Purpose Statement to clarify that the that Planning Coordinators need to develop a methodology for, and perform an annual assessment of, Transfer Capabilities in the Near-Term Transmission Planning Horizon that are needed for reliable planning
- Modified Requirement R1 to provide further clarity.
- Added a requirement to obligate Planning Coordinators, upon request, to provide data to support the assessment results.
- Modified the Measures to better align with 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, Herb 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 Standard Processes Manual.

Index to Questions, Comments, and Responses

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	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.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1

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

15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	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

				1	2	3	4	5	6	7	8	9	10
2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
4.	Bob Jones	Southern Company Services, Inc. - Trans.	SERC	1
5.	Pat Huntley	SERC Reliability Corporation	SERC	10

				1	2	3	4	5	6	7	8	9	10
3.	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.	Kyle Kohne	BPA, Transmission, Planning	WECC	1
3.	James Randall	BPA, Transmission, Planning	WECC	1
4.	Rebecca Berdahl	BPA, Power, Long Term Sales and Purchases	WECC	3

				1	2	3	4	5	6	7	8	9	10
4.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	Matthew Goldberg	ISO NE	NPCC	2
3.	Greg Campoli	NY ISO	NPCC	2

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

4.	Mark Tompson	AESO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Steve Myers	ERCOT	ERCOT	2
7.	Bill Phillips	MISO	RFC	2
8.	Matt Morias	ERCOT	ERCOT	2
9.	Kathleen Goodman	ISO NE	NPCC	2
10.	Jason Marshall	MISO	RFC	2
11.	Albert DiCaprio	PJM	RFC	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Paul Allen	Tampa Electric Company	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jorge Haylock		FRCC	1, 3, 5

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

2. Beth Young		FRCC	1, 3, 5
3. Jose Quintas		FRCC	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
7.	Group	W. R. Schoneck	FPL Transmission Planning	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1.	John W. Shaffer	FPL	FRCC
2.	Kiko Barredo	FPL	FRCC

				1	2	3	4	5	6	7	8	9	10
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

Additional Member	Additional Organization	Region	Segment Selection	
1.	Timothy Beyrle	Utilities Commission, City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4

				1	2	3	4	5	6	7	8	9	10
9.	Individual	Randall McCamish	FMPA	X		X							
10.	Individual	Brent Ingebrigtson	LG&E and KU Energy LLC	X		X		X	X				
11.	Individual	Andy Tillery	Southern Company	X		X							
12.	Individual	JC Culberson	ERCOT		X								
13.	Individual	Ross Kovacs	Georgia Transmission Corporation	X									
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Individual	Darrin Adams	East Kentucky Power Cooperative, Inc.	X		X		X					
16.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
17.	Individual	Jonathan Appelbaum	United Illuminating	X									
18.	Individual	Aaron Staley	Orlando Utilities Commission	X									
19.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
20.	Individual	Bob Easton	WAPA-RMR	X								X	
21.	Individual	Steve Rueckert	WECC										X
22.	Individual	Kathleen Goodman	ISO New England Inc.		X								
23.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
24.	Individual	Jason Marshall	Midwest ISO		X								
25.	Individual	John Bussman	AECI	X		X		X	X				
26.	Individual	Dan Rochester	Independent Electricity System Operator		X								
27.	Individual	J. S. Stonecipher, PE	Beaches Energy Services (of the City of Jacksonville Beach, FL)	X								X	
28.	Individual	Darcy O'Connell	California ISO		X								
29.	Individual	Laurie Williams	PNMR	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
30.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
31.	Individual	Bart White	Progress Energy Florida	X		X		X	X				
32.	Individual	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				
33.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				

1. **The SDT has modified the definition of Planning Transfer Capability (PTC). The definition now reads “The Transfer Capability that is calculated for the planning period beyond 13 months.” Do you agree that the revised definition provides additional clarity as to the time period for the calculations?**

Summary Consideration: Although many stakeholders agreed that the revisions to the definition of the term Planning Transfer Capability provided additional clarity, several commenters felt that the new term was not necessary or needed additional clarity as to whether the term was defining the total amount available or the incremental amount available. The SDT responded to the stakeholders by removing the proposed term. The SDT also explained that the standard’s emphasis was on assessment of future reliability and facilities that may be impacted by changes in power transfers, not specific transfer capability values. In addition, the SDT explained that the concept of a transfer capability assessment in the Near-Term Planning Horizon had been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	The creation of a new term is not necessary. ATC and TTC should be used.
Response: The SDT agrees and has dropped the term. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The industry does not support calculation of ATC beyond the operating horizon.		
ISO New England Inc.	No	The creation of a new term is unnecessary. ATC and TTC should be utilized.
Response: The SDT agrees and has dropped the term. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The industry does not support calculation of ATC beyond the operating horizon.		
Florida Municipal Power Agency	No	It is unclear whether PTC is allegorical to TTC or to ATC. The term should be modified to clarify whether PTC is the total or the incremental available. Without this clarity, on PC might calculate a total whereas its neighboring PC calculate an incremental available value and the numbers will be dramatically different causing confusion. Also, it leaves the values of PTC open to interpretation.FMPA recommends that PTC be calculated as the total; however, the PC should also report the TRM, CBM and existing long term firm commitments assumed so that entities understand that the total may not all be available (e.g., in the PTCMD).
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning		

Organization	Yes or No	Question 1 Comment
Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
FMPA	No	It is unclear whether PTC is allegorical to TTC or to ATC. The term should be modified to clarify whether PTC is the total or the incremental available. Without this clarity, on PC might calculate a total whereas its neighboring PC calculate an incremental available value and the numbers will be dramatically different causing confusion. Also, it leaves the values of PTC open to interpretation.FMPA recommends that PTC be calculated as the total; however, the PC should also report the TRM, CBM and existing long term firm commitments assumed so that entities understand that the total may not all be available (e.g., in the PTCMD).
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Beaches Energy Services (of the City of Jacksonville Beach, FL)	No	It is unclear whether PTC is allegorical to TTC or to ATC. The term should be modified to clarify whether PTC is the total or the incremental available. Without this clarity, on PC might calculate a total whereas its neighboring PC calculate an incremental available value and the numbers will be dramatically different causing confusion. Also, it leaves the values of PTC open to interpretation.Beaches Energy Services (BES) recommends that PTC be calculated as the total; however, the PC should also report the TRM, CBM and existing long term firm commitments assumed so that entities understand that the total may not all be available (e.g., in the PTCMD).
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Independent Electricity System Operator	No	We continue to disagree with the need to define these terms. A review of the Comment Report also suggests that the majority of the commenters disagree with the need to define these terms. We are disappointed that the SDT chose to ignore the majority comments.Our previous comments suggested that the term PTC does not provide any material difference than the term Transfer Capability, which has been defined and adopted for a long period of time. The industry is familiar with this definition, and has 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. The proposed definition for PTC is redundant and trivial since it still uses Transfer Capability as a defined term, with additional wording to indicate it is calculated for the planning period only. We believe this distinction can be achieved simply by insetting the phrase "in the planning period" to the term Transfer Capability in the appropriate requirements of the standard. Creating additional definitions require

Organization	Yes or No	Question 1 Comment
		additional maintenance of the glossary, and may create conflicting understanding for the same terms defined in different jurisdiction and documents (e.g. regional standards, legislation, etc.), and is to be avoided if words in the standards can convey the same intent/meaning.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. No new definitions are necessary.		
Xcel Energy	No	Xcel Energy continues to disagree with the need to create the term Planning Term Capability (PTC) for essentially the same reasons cited in our comments to the previous posting, that is, the existing glossary terms "Transfer Capability" and "Total Transfer Capability" are more than sufficient for the purposes of this standard. The proposed modified definition of PTC intends to clarify the time horizon to which the Transfer Capability applies - we do not see the need and/or value of a new glossary term simply to clarify that the applicability of Transfer Capability in the context of this standard is for the planning time horizon. Further, we are not persuaded by SDT's assertion that PTC is "necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose." in its response to the vast majority of commenters in the previous posting (First Energy, Bonneville Power Administration, Independent Electricity System Operator, IRS Standards Review Committee, Northeast Power Coordinating Council, Ameren, Midwest ISO Stakeholders) who commented that the existing terms Transfer Capability and Total Transfer Capability are well established, well understood and adequate. Please note that the existing definitions of TC and TTC are both a measure of electric power that can be reliably moved or transferred between areas *under specified system conditions* -- we do not see how this precludes the computation of TTC or TC for planning horizon system conditions.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon.. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
PNMR	No	NERC has done a poor job of addressing the confusion over TTC, PTC and System Operating Limits, and the difference between the concepts and reliability concerns addressed by FAC-010, FAC-014, the proposed FAC-013-2 and the MOD standards. As written, the proposed 13.2 just adds to this confusion. Transfer Capability should not be a term with different potential meaning between standards because of the period (planning versus operating) or use multiple phrases for the same quantity like SOL and transfer capability. NERC needs to step back and address clarifications on the terminology and concepts in existing standards

Organization	Yes or No	Question 1 Comment
		before any new standards on transfer capability methodology are approved. There are various terms used that are inconsistent between documents and need to be clarified (like "path" as used in R1 1.1 vs ATC path", "SOL" vs "transfer capability" vs "path rating") and the relationship of the standards needs to be clear and not duplicative.The note in the introduction indicates that PTC “is not meant to be a starting point for calculation of” ATC. What is the starting point for calculation of available transmission capacity in the planning horizon? Reference to “any System Operating Limit” is made in MOD-029 yet the SOL Methodology only applies to the planning horizon while MOD-029 only applies to the Operations Planning horizon. How can a concept that only applies within one time-frame be used in a mutually exclusive other time-frame? The implied overlap of the proposed FAC13.2 between the MOD standards and FAC-010 indicates that FAC 13-2 is duplicative, unnecessary and confusing.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The SDT does not believe there is an overlap between the revised draft and the MOD standards and FAC-010. These deal with calculation of ATC/AFC and identification of SOL’s. The FAC-013 standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL’s.		
ERCOT	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability (“ATC”) may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability (“FCITC”) may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
American Transmission Company	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability (“ATC”) may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability (“FCITC”) may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.

Organization	Yes or No	Question 1 Comment
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Midwest ISO	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
California ISO	Yes	The definition adds clarity regarding the time period for the calculations, however does not indicate the use or value of such calculations. We ask the SDT to explain what the difference is between PTCs and SOLs in the planning horizon. Calculation of PTCs appears to be duplicative of the calculation of SOLs in the planning horizon, and therefore duplicative with other existing NERC standards.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs.		
Kansas City Power & Light	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period		

Organization	Yes or No	Question 1 Comment
applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
IRC Standards Review Committee	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Tennessee Valley Authority	Yes	The revised definition of PTC does provide additional clarity as to the begin point of the intended time period. Transfer Capability is also calculated for time periods within the 13 month window for pre-seasonal operations planning studies. Is there a separate project / Standard Drafting Team addressing this time frame?
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The 13 month window is addressed by MOD-001, -028, 029 and -030.		
Bonneville Power Administration	Yes	The definition provides clarity as to the time period for the calculations. However, the purpose and need for calculating PTCs is still unclear. See comment in Question 8.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
MRO's NERC Standards Review Subcommittee	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by

Organization	Yes or No	Question 1 Comment
		Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Georgia Transmission Corporation	Yes	
AECI	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
WAPA-RMR	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
Tampa Electric Company	Yes	
FPL Transmission Planning	Yes	
Progress Energy Florida	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 1 Comment
SERC Planning Standards Subcommittee	Yes	
WECC		The revised definition clarifies the time period for the calculations of PTC. However, the purpose and need for calculationg PTCs is unclear. What is the difference between an SOL for the Planning horizon and a PTC that must respect all SOLs. It appears that in the end one would end up with the same value. Please provide an example of how an SOL and a PTC differ.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs.		

2. **The SDT has modified the definition of Planning Transfer Capability Implementation Document (PTCID) so that it is now called Planning Transfer Capability Methodology Document (PTCMD). The definition now reads "A document that describes the process for calculating Planning Transfer Capability (PTC)." Do you agree that the revised definition provides additional clarity as to the purpose of the document?**

Summary Consideration: The majority of negative commenters were confused as to the intent of the Planning Transfer Capability Methodology Document. The SDT explained that the PTC and PTCMD definitions had been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon had been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. Further, the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values.

Organization	Yes or No	Question 2 Comment
IRC Standards Review Committee	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of atransfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and		

Organization	Yes or No	Question 2 Comment
facilities that may be impacted by changes in transfers - not specific transfer capability values.		
MRO's NERC Standards Review Subcommittee	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
ERCOT	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such

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		that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.Absent a transmission service market, transfer capabilities are not applicable; therefore, there would be no benefit in developing a PTCMD.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. Transfers occur between all areas, even non-market areas – the SDT does not understand the basis for this comment.		
American Transmission Company	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of "ATC" for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as "ATC" and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which "ATC" values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of "ATC" values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4).
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and		

Organization	Yes or No	Question 2 Comment
facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Midwest ISO	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Kansas City Power & Light	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such

Organization	Yes or No	Question 2 Comment
		that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be “identical” between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Northeast Power Coordinating Council	No	Refer to the response to Question 1.
Response: See response to Q1		
ISO New England Inc.	No	See comment #1
Response: See response to Q1.		
Independent Electricity System Operator	No	For the same reason indicated under Q1, we disagree with the need to define PTCID.
Response: See response to Q1.		
Florida Municipal Power Agency	No	Mention should be made of the assumptions as well as the process / method
Response: The PTCMD definition has been deleted based on industry comments.		
FMPA	No	Mention should be made of the assumptions as well as the process / method.
Response: The PTCMD definition has been deleted based on industry comments.		

Organization	Yes or No	Question 2 Comment
Beaches Energy Services (of the City of Jacksonville Beach, FL)	No	Mention should be made of the assumptions as well as the process / method.
Response: The PTCMD definition has been deleted based on industry comments.		
California ISO	No	How is this definition and methodology different from the SOL methodology for the planning horizon in FAC-010-2.1? What is the difference between PTCs and SOLs in the planning horizon? Is FAC-013-2 duplicative with FAC-010-2.1 and FAC-014, and therefore potentially unnecessary?
Response: The PTCMD definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs.		
PNMR	No	See previous comment.
Response: See response to Q1.		
Xcel Energy	No	Xcel Energy believes that it is not necessary to create a new defined term, whether PTCID or PTCMD, for the following reasons: (1) We are unable to appreciate why the existing use of Transfer Capability Methodology within FAC-012-1 (which is not a defined term) becomes inadequate for continued usage - is there anything in the FERC Order 729 that requires defining TCMD? (2) We believe that continuing usage of Transfer Capability Methodology by stating the term within parenthesis at its first occurrence in R1 within the relevant standard will be wholly consistent with the existing paradigm - note that the term Facility Ratings Methodology is only used in FAC-008, and the term SOL Methodology is only used in FAC-010/011, and none of them are glossary terms.
Response: The PTCMD definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon.		
WAPA-RMR	Yes	The process outlined in the proposed FAC-013-2 is defined within the WECC at this time as the Path Rating Process. This proposed FAC seems duplicative to this existing practice in WECC.

Organization	Yes or No	Question 2 Comment
Response: Some existing practices may be duplicative of this standard. Therefore, compliance with the new standard should be more easily achieved.		
AECI	Yes	
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
Southern Company	Yes	
Tampa Electric Company	Yes	
FPL Transmission Planning	Yes	
Progress Energy Florida	Yes	
Tennessee Valley Authority	Yes	
SERC Planning Standards Subcommittee	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
WECC		Agree with the revised definition, but as indicated in the response to question 1, what is the need?
Response: The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
LG&E and KU Energy LLC		

3. The SDT has modified the Requirements to include data and modeling information as well as provide for additional clarity regarding the intent of the Requirement. Do you agree that the revised Requirements accomplish this goal?

Summary Consideration: Several of the negative commenters asked for further clarity as to the intent of the standard and the Planning Transfer methodology Document. The SDT explained that the standard had been clarified to be applicable to the Near-Term Transmission Planning Horizon and that the PTC and PTCMD definitions had been deleted based on industry comments. In addition, the concept of a transfer capability assessment in the Near-Term Planning Horizon had been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. Also, the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values.

Some of the negative commenters felt there should be a new sub-requirement added that required a listing of long term firm point to point transmission service that would consume PTC. The SDT explained that the current Requirement R1 Part 1.3 required that the current and projected transmission uses be addressed and that the long term point to point transmission service data was available on transmission providers' OASIS.

A few of the negative comments indicated confusion as to the intent of Requirement R1 Part 1.3 and questioned why Requirement R1 Part 1.4 was in the standard. They also questioned whether the last bullet of Requirement R1 Part 1.1 was necessary. The SDT removed the last bullet in Requirement R1 Part 1.1 from the standard. The intent of Requirement R1 Part 1.3. (now Requirement R1 Part 1.2) was to ensure the methodology required the processes Planning Coordinators use to determine and assess transfer capabilities with respect to all applicable known SOLs. Requirement R1 Part 1.4. (now Requirement R1 Part 1.3) was included to implement a FERC directive.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	R1-part 1.1-last bullet - Referring to the following text: "Reliability margins applied to reflect uncertainty with BES conditions." The language requires that a reducing factor should be applied to calculated transfer capabilities to account for uncertainty in BES conditions. The document requires the user to modify, through a probabilistic approach, the base system representation with respect to the in-service status of BES elements. This consideration is currently not part either of the methodology employed for transfer capability calculations, nor is it acceptable to employ it going forward, given the fact that a transmission adequacy assessment such as this one is deterministic in nature. Moreover, transfer capability, from a planning perspective, is performed assuming all commercially operating system elements in service. On the other hand, the calculation of System Operating Limits is an assessment of specific system conditions projected for the short term horizon (e.g. seasonally). The probabilistic treatment of BES elements, with respect to their in-

Organization	Yes or No	Question 3 Comment
		service status, is currently already employed in other types of reliability analysis, such as LOLE (Loss of Load Expectation) assessments.Requirement 1.3 is unclear as to what the intent is. With respect to R1.4, what is the need or basis for this requirement? Requirement R3 is inconsistent with established and accepted regional practices and needs to make allowances for these.
Response: **T**he referenced last bullet has been removed from the standard. The intent of Requirement R1 Part 1.3 (now Requirement R1 Part 1.2) is to ensure the methodology requires the processes Planning Coordinators use to determine and assess transfer capabilities respect all applicable known SOLs. Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is include to address a FERC directive. The SDT is not clear how Requirement R.3. is, or could be, inconsistent with any regional practices.		
Independent Electricity System Operator	No	We concur with the list of elements to be addressed in R1.1, and with the inclusion of R1.2 and R1.5, but have the following comments on R1.3 and R1.4.R1.3 - For clarity we recommend appending " including IROLs."R1.4 should be removed. The appropriate assumptions are determined by the planning assessment personnel. The assumption can be more or less stringent than those applied in the operation horizon depending on the known and expected system conditions. Also, the criteria used in the two horizons can be different. For example, the TPL standards stipulate the contingency and performance requirements for planning assessment but the same set of comprehensive requirements do not currently exist for operation study or SOL/IROL calculations. Some in the industry have made it known that they would apply different contingency/performance criteria to operation assessment and in planning assessment. The industry's rejection to the SAR 2 years ago which proposed changes to FAC-010 and FAC-011 to achieve consistency in the planning and operation criteria provides this evidence.
Response: The SDT believes IROLs are included by definition and including again would be redundant. Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is included to address a FERC directive. It has been modified to include the phrase "… consistent with the Planning Coordinator's planning practices."		
ISO New England Inc.	No	Requirement R3 is inconsistent with established and accepted regional practices and needs to make allowances for these. Requirement 1.3 is unclear as to what the intent is, with respect to R1.4, what is the need or basis for this requirement?
Response: The SDT is not clear how R.3 is or could be, inconsistent with any regional practices. The intent of Requirement R1 Part 1.3 (now Requirement R1 Part 1.2) is to ensure the methodology requires the processes Planning Coordinators use to determine and assess transfer capabilities respect all known SOL's. Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is include to address a FERC directive. The SDT is not clear how Requirement R.3. is, or could be, inconsistent with any regional practices.		
FPL Transmission Planning	No	The Purpose of the standard states that Planning Transmission Capabilities are needed for reliable planning of the Bulk Electric System. The PTC forecasts need to be reliability based to be meaningful for planning by

Organization	Yes or No	Question 3 Comment
		determining adequate long term capability to ensure reliable operation in the future. Consistent with the stated purpose, Requirement R1.2 should be changed from “A list of all PTCs to be calculated” to “A list of PTCs to be calculated, which are needed for reliability planning coordination”
Response: The standard has been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing the impacts of transfers on facilities in the Near-Term Transmission Planning Horizon. The standard no longer references or requires calculation of PTCs.		
Florida Municipal Power Agency	No	A new sub-requirement should be added that requires listing of existing long term firm point to point transmission service that would consume PTC (assuming PTC is a “total” and not an “available” number).
Response: Requirement R1 Part 1.3 requires that the current and projected transmission uses be addressed. This data is available on transmission providers’ OASIS.		
FMPA	No	A new sub-requirement should be added that requires listing of existing long term firm point to point transmission service that would consume PTC (assuming PTC is a “total” and not an “available” number).
Response: Requirement R1 Part 1.3 requires that the current and projected transmission uses be addressed. This data is available on transmission providers’ OASIS.		
Beaches Energy Services (of the City of Jacksonville Beach, FL)	No	A new sub-requirement should be added that requires listing of existing long-term firm, point-to- point transmission service that would consume PTC (assuming PTC is a “total” and not an “available” number).
Response: Requirement R1 Part 1.3 requires that the current and projected transmission uses be addressed. This data is available on transmission providers’ OASIS.		
IRC Standards Review Committee	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include “a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...”. Included in these required elements, at Part 1.1, are “Reliability margins applied to reflect uncertainty with BES conditions” and, at R1.4, are “A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon”. The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon.

Organization	Yes or No	Question 3 Comment
		More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon. The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
MRO's NERC Standards Review Subcommittee	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning

Organization	Yes or No	Question 3 Comment
		Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include “a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...”. Included in these required elements, at Part 1.1, are “Reliability margins applied to reflect uncertainty with BES conditions” and, at R1.4, are “A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon”. The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon. More specifically, the requirement to include ‘Reliability Margins’ in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC’s final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System (“BES”) will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that ‘A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon’ be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities “may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning.” Hence, if the intent of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC’s guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity’s methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity’s methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.

Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw

Organization	Yes or No	Question 3 Comment
distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
ERCOT	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon. More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as

Organization	Yes or No	Question 3 Comment
		described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.Again, in a Region that does not have a transmission service market, the concept of transfer capabilities is not applicable, leaving no benefit to developing a PTCMD.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
American Transmission Company	No	As discussed in Question 2, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of "ATC" values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of "ATC" values for the Planning Horizon. More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated "ATC" values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of "ATC" values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of "ATC" values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and

Organization	Yes or No	Question 3 Comment
		would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities “may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning.” Hence, if the intent of this standard and the PTCMD is to describe an entity’s methodology for calculation of “ATC” values for the Planning Horizon, such is contrary to FERC’s guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity’s methodology for calculation of “ATC” values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity’s methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Midwest ISO	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include “a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...”. Included in these required elements, at Part 1.1, are “Reliability margins applied to reflect uncertainty with BES conditions” and, at R1.4, are “A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon”. The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon. More specifically, the requirement to include ‘Reliability Margins’ in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC’s final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System (“BES”) will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that ‘A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon’ be included in the PTCMD indicates that the assumptions and criteria utilized to

Organization	Yes or No	Question 3 Comment
		calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Kansas City Power & Light	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon. More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling

Organization	Yes or No	Question 3 Comment
		transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
California ISO	No	The intention of the FAC-013-2 standard is not clear. Are PTCs different from SOLs for the planning horizon? It appears duplicative with other existing NERC standards.
Response: The concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>PNMR</td><td>No</td><td>This should be written to clarify the differences used in determining transfer capability in the planning horizon from determining transfer capability in the operations [or Operations Planning] horizon.</td></tr>
<tr><td colspan="3">Response: The concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.</td></tr>
<tr><td>Progress Energy Florida</td><td>No</td><td>R1.1 is adequate in general, but the inclusion of "Parallel path impacts (loop flows)" is inappropriate and inconsistent with the types of analyses that would be used to calculate PTC as stipulated in the existing TPL Standards. We suggest that the loop flow language be deleted.Furthermore, the Purpose of the standard states that calculating Planning Transfer Capabilities is for the reliable planning of the BES. Since the Purpose in A3 states that the calculation of PTC is limited to use for reliable planning, R1.2 should clarify this issue. We suggest editing R1.2 to state "A list of PTCs to be calculated as needed for the reliable planning of the Bulk Electric System". Such a modification is necessary in order for the work performed for FAC-013-2 to be consistent with the stated purpose in A3. We furthermore assert that the use of the word "all" is confusing and could lead PCs to interpret the extent of a PTC list in various ways, which is why we excluded it from our above suggested modifications.</td></tr>
<tr><td colspan="3">Response: The SDT changed "Parallel path impacts (loop flow)" to read "Parallel path (loop flow) adjustments" to clarify what was intended. Additionally, the standard has been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing transfer capabilities in the Near-Term Transmission Planning Horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.</td></tr>
<tr><td>Tennessee Valley Authority</td><td>No</td><td>The intent of the standard still lacks clarity. The purpose statement 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)." Resource Planners within a Planning Coordinator's area need an awareness of Planning Transfer Capability into their area of load responsibility in order to plan for sufficient resources inside the area. There is no requirement in the standard to communicate Transfer Capability to the Resource Planners within the Planning Coordinator's area.

The proposed standard does not require any coordination between Planning Coordinators in performing these calculations. Planning Transfer Capability that is calculated outside of a jointly coordinated Planning Coordinator study process will likely produce forecasts of Planning Transfer Capability that are less reflective of planned system capabilities.Under R1.1.1, we believe that "monitored facilities" assumptions and criteria should also be addressed in the PTCMD.We believe that requirement R1.1.3 should be modified to reflect</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		that PTC calculations respect TPL criteria as a basis for PTC calculations, rather than SOLs.The intent of R1.1.4 is unclear, particularly since the standard excludes calculation of Transfer Capability in the operating horizon (inside 13 months).
Response: The SDT believes that Requirement R2, Part 2.2 in the revised standard provides the means for Resource Planners within the Planning Coordinator's area to provide input in to and receive data from a Planning Coordinator's processes as part of this standard. Monitored facilities criteria have been added to Requirement R1 Part 1.1. (now Requirement R1 Part 1.4.). Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is included to address a FERC directive. It has been modified to include the phrase "… consistent with the Planning Coordinator's planning practices." Requirements R2, R3 and R5 to share methodologies, and associated assessment results and supporting data adequately addresses coordination between Planning Coordinators.		
Bonneville Power Administration	Yes	While BPA understands the intent that the revised R1.1 does not limit the Planning Coordinator's ability to use additional assumptions and criteria in the calculation of Planning Transfer Capabilities, Bonneville believes R1.1 is unclear as written. Bonneville requests R1.1 to be changed to:"A description of the assumptions and criteria used in the calculation of Planning Transfer Capability (PTC)s to include, but not limited to, how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC." For example, Bonneville wants to ensure that assumptions and criteria such as ambient temperature can be considered in calculating PTCs.
Response: The SDT has modified Requirement R1 Part 1.1. (now Requirement R1 Part 1.4.) to improve the clarity of the requirement. Overall, R1 and the standard have been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing the impact of transfers on facilities in the Near-Term Transmission Planning Horizon.		
Xcel Energy	Yes	Suggest re-sequencing the parts within R1 so that the existing part 1.1 follows the existing part 1.4 and is immediately before the existing part 1.5 since part 1.5 is related to the assumptions/criteria listed within part 1.1. This will also result in part 1.2 (list of Transfer Capabilities) to be stated at the very beginning.
Response: The SDT has modified and re-sequenced parts within R1.		
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
WAPA-RMR	Yes	
Southern Company	Yes	
Tampa Electric Company	Yes	
SERC Planning Standards Subcommittee	Yes	
AECI	Yes	

4. The SDT has modified the VRFs to better align with the risk associated with the Requirements. Do you agree that the VRFs are now more consistent with regards to the risk associated with the Requirements?

Summary Consideration: The majority of the industry stakeholders agreed that the VRFs were now more consistent with the risk associated with the Requirements.

However, one stakeholder felt that the VRFs should be in a table attached to the standard. The SDT explained that the location of the VRF's for this standard were consistent with NERC's standards format.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	Suggest listing the VRFs in a table as an attachment to the document.
Response: The location of the VRF's for this standard is consistent with NERC's standards format.		
PNMR	No	There is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1.
Response: The SDT agrees and has modified the VSL for R1 to eliminate the overlap.		
Bonneville Power Administration	Yes	BPA agrees that the VRFs for all the requirements in FAC-013-2 should be Lower.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
IRC Standards Review Committee	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
MRO's NERC Standards Review Subcommittee	Yes	We thank the drafting team for revising these VRFs to be Lower. We understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Tampa Electric Company	Yes	Agree all should be lower
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Kansas City Power & Light	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
FPL Transmission Planning	Yes	Agree that all requirements of this standard as drafted should be Lower.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
ERCOT	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
American Transmission Company	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Midwest ISO	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 4 Comment
California ISO	Yes	We appreciate that the drafting team revised the VRFs to be "Lower". While we question the need for the FAC-013-2 standard and whether it is duplicative with other existing NERC standards, we understand that requirements must include VRFs and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
AECI	Yes	
Independent Electricity System Operator	Yes	
Beaches Energy Services (of the City of Jacksonville Beach, FL)	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
Florida Municipal Power Agency	Yes	
FMPA	Yes	
Southern Company	Yes	
Georgia Transmission Corporation	Yes	

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	
Progress Energy Florida	Yes	
Tennessee Valley Authority	Yes	
SERC Planning Standards Subcommittee	Yes	
WAPA-RMR		No comments on VRFs.

5. The SDT has modified the Measures to better align with the Requirements. Do you agree that the Measures are now more consistent with the Requirements?

Summary Consideration: Most of the negative commenters felt that Measures M3 and M4 were simply restatements of the Requirements. The SDT modified Measures M3 and M4 to remove any restatement of the Requirements.

A couple of the negative comments indicated that the Measures should be consistent with regional practices. The SDT does not feel that enough information was provided within the comment for the SDT to understand the concern but the SDT did modify Measures M3 and M4 to provide additional clarity based on other stakeholder comments. Measures need to be consistent with the requirements in the continent-wide standard since they need to be applicable across all Regions.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	Measures should be consistent with regional practices.
Response: Measures need to be consistent with the requirements in the continent-wide standard since they need to be applicable across all Regions. The SDT thanks you for your response but does not believe that they have enough information to understand your concern. However, the SDT did revise Measures M3 and M4 to provide additional clarity.		
ISO New England Inc.	No	Measures should be consistent with regional practices.
Response: Measures need to be consistent with the requirements in the continent-wide standard since they need to be applicable across all Regions. The SDT thanks you for your response but does not believe that they have enough information to understand your concern. However, the SDT did revise Measures M3 and M4 to provide additional clarity.		
Florida Municipal Power Agency	No	M3 and M4 are simply restatements of the requirements. FMPA suggests adding “such as (examples of evidence)” statements similar to those provided in M1, M2 and M5.
Response: The SDT has revised Measures M3 and M4 to provide examples of acceptable evidence as suggested. .		
FMPA	No	M3 and M4 are simply restatements of the requirements. FMPA suggests adding “such as (examples of evidence)” statements similar to those provided in M1, M2 and M5.

Organization	Yes or No	Question 5 Comment
Response: The SDT has revised Measures M3 and M4 to provide examples of acceptable evidence as suggested.		
Beaches Energy Services (of the City of Jacksonville Beach, FL)	No	M3 and M4 are simply restatements of the requirements. BES suggests adding “such as (examples of evidence)” statements similar to those provided in M1, M2 and M5.
Response: The SDT has revised Measures M3 and M4 to provide examples of acceptable evidence as suggested.		
Southern Company	No	
California ISO	Yes	
SERC Planning Standards Subcommittee	Yes	
Bonneville Power Administration	Yes	
IRC Standards Review Committee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Tampa Electric Company	Yes	
FPL Transmission Planning	Yes	
Xcel Energy	Yes	
Progress Energy Florida	Yes	
Tennessee Valley Authority	Yes	
Kansas City Power & Light	Yes	

Organization	Yes or No	Question 5 Comment
Midwest ISO	Yes	
AECI	Yes	
Independent Electricity System Operator	Yes	
ERCOT	Yes	
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
WAPA-RMR	Yes	
American Transmission Company	Yes	

6. The SDT has modified the VSLs to better align with the severity of non-compliance associated with the Requirements. Do you agree that the VSLs are now more consistent with regards to the severity of non-compliance associated with the Requirements?

Summary Consideration: Several of the negative commenters indicated that the VSLs for Requirement R1 should be expanded to include more gradations. The VSL for Requirement R1 was extensively revised and modified to be consistent with the new Requirement R1 and industry stakeholder comments. The SDT believes the revised gradations are now appropriate for each sub-part.

A few of the negative comments indicated an overlap in the lower and moderate VSLs for Requirement R1. The SDT modified the VSLs to be consistent with the new Requirement R1 and industry stakeholder comments and eliminated the overlap. Some commenters suggested that there should be High and Severe VSLs for noncompliance with Parts 1.4 and these were added. The SDT assigned a Lower VSL for failure to address one or two of the items listed in Requirement R1 Part 1.4; Moderate VSL for failure to miss three; High for missing four; Severe for missing more than four. A couple of the negative comments indicated that the VSLs were inconsistent in their numbering scheme and the term “notified” should be replaced with “made available to” in the VSLs for Requirement R5. Requirement R1 was extensively revised and the VSLs were modified to be consistent with the new Requirement R1. The SDT revised the wording in the VSL for Requirement R5 as noted by stakeholders to use the same phrasing, “made . . . available to” as used in the associated requirement. The SDT chose the increments for Requirements R1, R2, R3 and R5 that vary depending on the content of the requirement – this supports NERC’s VSL Guidelines.

Organization	Yes or No	Question 6 Comment
WECC	No	There appears to be a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or TWO of the items listed in Requirement R1, Part 1.1.The second part of the Moderate VSL reads:The Planning Coordinator has a PTCMD but failed to address TWO or more of the items listed in Requirement 1, Part 1.1If the PC has a PTCMD but failed to address TWO of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. Suggest you change the second part of the Moderate VSL to readThe Planning Coordinator has a PTCMD but failed to address THREE or more of the items listed in Requirement 1, Part 1.1
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to “The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4”; “The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in		

Organization	Yes or No	Question 6 Comment
Requirement R1 Part 1.4.”		
FPL Transmission Planning	No	The VSLs for R1 Lower and Moderate are inconsistent or contain an error. Recommend changing Moderate VSL (second part) to “The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1. The High and Severe VSLs for R1 should spell out the numerical 2 and 3 as “two” and “three” for consistency. The changes in severity levels for R2, R3, and R5 should be in multiples of 30 days, not in multiples of 10 days, which seems haphazardly chosen and severe for requirements that all have Lower VRFs. Similarly, R4 should be in multiples of 25% rather than 5%, particularly since there should not be a need to calculate very many PTCs because they should only be calculated for reliability enhancement reasons. Finally, the word “notified” in each VSL for R5 should be replaced with “made available to” in order to be consistent with the wording in R5.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to “The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4”; “The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4.” The SDT chose increments for R2, R3 and R5 that vary depending on the content of the requirement. R4 in the initial draft of FAC-013-2 has been replaced; the new VSLs for R4 do not use multiples. The SDT has modified Requirement R5 VSL to address your concern and the word, ‘notified’ was replaced with ‘made. . . . available’.		
California ISO	No	A revision to the VSL for R1 is needed. As currently proposed, there is an overlap (with “two” of the items) appearing in both the Lower and Moderate VSL for R1. If an entity fails to meet “two” of the items listed in requirement R1, Part 1.1, the entity would meet the language currently contained in both the Lower and in the Moderate VSL. We recommend the SDT change the second part of the Moderate VSL to read: “The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1”
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to “The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4”; “The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4.”		

Organization	Yes or No	Question 6 Comment
SERC Planning Standards Subcommittee	No	Revise the High VSL for R3 to: The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 70 calendar days, but not more than 80 calendar days after receipt of the comment. Revise the Severe VSL for R3 to: The Planning Coordinator failed to provide a documented response to a documented technical comment as required in R3 within 80 calendar days after receipt of the comment. Revise the High VSL for R5 to: The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs after 70 calendar days, but not more than 80 calendar days after their verification and recalculation. Revise the Severe VSL for R3 to: The Planning Coordinator failed to notify one or more of the parties specified in Requirement R5 of its PTCs within 80 calendar days after their verification and recalculation. The Lower VSLs for R3 and R5 appear to violate the NERC VSL guideline that increments for time frames should be no more than 10 days.
Response: The SDT agrees with the intent of your proposed modification for the High VSL for R3 and made a conforming change. The high VSL for Requirement R3 now reads “The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days.” The severe VSL for Requirement R3 now reads “The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 by more than 90 calendar days. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability Methodology.” The High VSL and Severe VSL for Requirement R5 have been modified to “The Planning Coordinator made its documented Transfer assessment available to one or more of the recipients of its Transfer Capability Methodology more than 75 calendar days after completion of the assessment, but not more than 90 calendar days after completion of the assessment” and “The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than 90 calendar days after completion of the assessment OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability Methodology.” The NERC VSL guideline allows for justifiable deviations from the default 10-day increments.		
South Carolina Electric and Gas	No	Revise the High VSL for R3 to: "The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 70 calendar days, but not more than 80 calendar days after receipt of the comment." Revise the Severe VSL for R3 to: "The Planning Coordinator failed to provide a documented response to a documented technical comment as required in R3 within 80 calendar days after receipt of the comment." Revise the High VSL for R5 to: "The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs after 70 calendar days, but not more than 80 calendar days after their verification and recalculation." Revise the Severe VSL for R3 to: "The

Organization	Yes or No	Question 6 Comment
		Planning Coordinator failed to notify one or more of the parties specified in Requirement R5 of its PTCs within 80 calendar days after their verification and recalculation." The Lower VSLs for R3 and R5 appear to violate the NERC VSL guideline that increments for time frames should be no more than 10 days.
Response: The SDT agrees with the intent of your proposed modification for the High VSL for R3 and made a conforming change.. The high VSL for Requirement R3 now reads "The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days." The severe VSL for Requirement R3 now reads "The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 by more than 90 calendar days. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability Methodology." The High VSL and Severe VSL for Requirement R5 have been modified to "The Planning Coordinator made its documented Transfer assessment available to one or more of the recipients of its Transfer Capability Methodology more than 75 calendar days after completion of the assessment, but not more than 90 calendar days after completion of the assessment" and "The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than 90 calendar days after completion of the assessment OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability Methodology." The NERC VSL guideline allows for justifiable deviations from the default 10-day increments.		
IRC Standards Review Committee	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
MRO's NERC Standards Review Subcommittee	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.

Organization	Yes or No	Question 6 Comment
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
ERCOT	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: **R**equirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
American Transmission Company	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
Midwest ISO	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate

Organization	Yes or No	Question 6 Comment
		VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
Kansas City Power & Light	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address more three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
Tampa Electric Company	No	Chnages in severity levels should be based on 30 days not 10 days
Response: The SDT is unaware of a guideline that would have severity levels based on 30 days. The SDT chose increments for each requirement with increments that vary depending on the content of the requirement.		
Progress Energy Florida	No	The VSLs have an inconsistent numbering convention. For example the R1 Lower VSL uses the phrase "one or two of the items" while several other use numerals, e.g. the R1 Moderate VSL uses the phrase "1 of the items". We suggest spelling out the amounts as words rather than using numerals. Furthermore, the R2, R3, and R5 VSLs seem to apply time limits inconsistently, e.g. the R3 High VSL has a limit of 70 days whereas the R5 High VSL time limit has a limit of 80 days. We recommend that the SDT reevaluate the reasoning behind all of the time limits and consider a more standardized approach. Additionally, the word "notified" in the R5 VSLs should be changed to "made available to", along with other rearrangement of wording. For

Organization	Yes or No	Question 6 Comment
		example, the R5 Lower VSL should read "The Planning Coordinator made its PTCs available to one or more of the parties specified in Requirement R5 more than 30 calendar days after their verification and recalculation, but not more than 60 calendar days after their verification and recalculation". This edit is needed in order for the R5 VSLs to be consistent with the wording in R5.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address more than two of the items listed in Requirement R1 Part 1.4." The SDT chose increments for R2, R3 and R5 with increments that vary depending on the content of the requirement. The SDT has modified the VSL for Requirement R5 to address you concerns.		
Southern Company	No	
Bonneville Power Administration	Yes	The VSLs are now more consistent with the severity levels, however there is some overlap between the Lower and Moderate VSL for R1. Bonneville proposes the following changes to the VSLs for R1:Lower VSL:The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1.Moderate VSL:The Planning Coordinator has a PTCMD but failed to incorporate 1 of the items listed in Requirement R1, Parts 1.2 through 1.5 ORThe Planning Coordinator has a PTCMD but failed to address two three or more of the items listed in Requirement 1, Part 1.1.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." The SDT feels that the gradations are now appropriate for each sub-part.		
AECI	Yes	
Independent Electricity System Operator	Yes	
Beaches Energy Services (of the City of Jacksonville Beach, FL)	Yes	

Organization	Yes or No	Question 6 Comment
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
Florida Municipal Power Agency	Yes	
FMPA	Yes	
Northeast Power Coordinating Council	Yes	
WAPA-RMR		No comments on VSLs.

7. When reviewing the mapping document posted with the proposed FAC-013-2 standard, do you believe that the proposed standard (considering only the requirements assigned to the Planning Coordinator) will lead to an improvement in reliability when compared to the standards it proposes to replace?

Summary Consideration: Most of the negative commenters did not agree that the proposed standard provided any additional clarity or planning value. The SDT explained that they believed there was a reliability related need for this assessment to be conducted and that the standard's emphasis was on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT did not believe that the TPL standards adequately covered the need at this time.

Some of the negative comments indicate that the additional requirements included in the new FAC-013-2 standard when compared to the FAC-012-1 did not add much value in terms of increased reliability. The SDT explained that this draft standard merges the planning requirements in FAC-012-1 and FAC-013-1 and that the standard's emphasis was on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes that the TPL standards did not adequately cover the need at this time and that coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy.

A few of the negative comments indicated that the current draft of the FAC-013-2 standard caused confusion regarding the difference between a PTC and an SOL in the planning horizon. The PTC definition was deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon was clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. In addition, the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values nor defining SOLs.

A couple of the negative comments indicated that this standard neglected that modeling information and decisions that go into calculating accurate transfer capability, and choosing meaningful paths to calculate, require close coordination and discussions between the parties involved. The proposed standard does not preclude entities from working cooperatively to develop their Planning Transfer Capability Methodologies. This standard would increase transparency, and develop a level of coordination that may not exist in all NERC regions. In addition, the TPL standards do not adequately cover the need at this time. This standard requires a response to written comments from parties that have a reliability related need for the assessment results and coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities while Order 890 processes do not and in many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice and therefore, this new standard codified these practices.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	This standard provides no additional reliability or planning value to the TPL Standards.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
IRC Standards Review Committee	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT has made significant clarifying changes to the draft requirements based on comments provided by the industry.		
ERCOT	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT has made significant clarifying changes to the draft requirements based on comments provided by the industry.		
United Illuminating	No	Since it is replacing an existing requirement there will be no improvement to reliability. It adds some clarity to the process.
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
Bonneville Power Administration	No	Bonneville requests the following requirement to be added as R1.3.1."R1.3.1 SOLs calculated in the Planning Horizon can be used as PTCs." In the previous comment period, Bonneville asked for clarity regarding how

Organization	Yes or No	Question 7 Comment
		calculating Planning Transfer Capabilities differ from calculating Total Transfer Capability and/or System Operating Limits. BPA understands that the SDT is trying to create a quantity that is not defined by TTCs or SOLs. However, the SDT responses did not adequately explain how a PTC is different; only that it would be calculated when no TTC or SOL is calculated. Also, it is unclear to Bonneville how the calculation of a PTC will enhance the Planning Coordinator's understanding of system behavior. The PTC term creates more confusion rather than avoiding confusion with TTC and SOL.As a result, it is unclear to BPA why this value (PTC) needs to be calculated and have an associated NERC standard. To better understand what the SDT is attempting to accomplish with FAC-013-2, Bonneville requests specific real-world examples of how calculating a PTC is different than calculating a System Operating Limit (SOL) or Total Transfer Capability (TTC) for the planning period beyond 13 months. Otherwise, it seems redundant with FAC-010 and FAC-014.Bonneville also requests clarity on the additional reliability need to calculate PTCs above and beyond the reliability need to calculate SOLs and TTCs in the planning period beyond 13 months.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's. Based on industry feedback Requi9rement R1 and the associated Parts have been modified to add clarity.		
MRO's NERC Standards Review Subcommittee	No	It is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The SDT has made significant clarifying changes to the draft requirements based on comments provided by the industry.		
WAPA-RMR	No	This proposed FAC-013 process is already in-place within the WECC (Three-Phase Rating Process).
Response: In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.		
ISO New England Inc.	No	This standard provides no reliability value addition to the TPL Standards.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
American Transmission Company	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding

Organization	Yes or No	Question 7 Comment
		reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
Midwest ISO	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
Kansas City Power & Light	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
AECI	No	The modeling information and decisions that go into calculating accurate transfer capability, and choosing meaningful paths to calculate, requires close coordination and discussions between the parties involved. The existing standards insure that this will happen by requiring involvement between planning coordinators, reliability coordinators, and their respective regional reliability organizations. Without that oversight, and the forums that have been developed within the regional reliability organizations, overall coordination will be more difficult to accomplish by the individual planning coordinators acting alone as implied by this proposed standard.
Response: The SDT believes that this standard will increase transparency, and develop a level of coordination that may not exist in all NERC regions. The		

Organization	Yes or No	Question 7 Comment
proposed standard does not preclude entities from working cooperatively to develop their Planning Transfer Capability Methodologies. The SDT does not believe the TPL standards adequately cover the need at this time. The standard requires response to written comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities while Order 890 processes do not. In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.		
Independent Electricity System Operator	No	We assess that the mapping would result in maintaining the same level of reliability, not necessarily an improvement in reliability.
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
East Kentucky Power Cooperative, Inc.	No	The additional requirements included in the new FAC-013-2 standard when compared to the FAC-012-1 do not add much value in terms of increased reliability. These items require the Planning Coordinator to simply describe in more detail which PTCs have been calculated and how. This will have minimal impact on reliability.
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. The standard requires response to written comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy.		
California ISO	No	The current draft of the FAC-013-2 standard has caused confusion. We request that the SDT clearly state the difference between a PTC and an SOL in the planning horizon. FAC-013-2 appears duplicative with other existing NERC standards (i.e., FAC-010-2.1 and FAC-014) and we question whether FAC-013-2 is necessary. How would the methodology differ for the calculation of PTCs compared to the calculation of SOLs in the planning horizon?
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's.		
Xcel Energy	No	Xcel Energy is unsure of the system reliability need and/or benefit of computing planning horizon transfer capability, as required under draft FAC-013-2 or the existing FAC-012/013 standards. The system reliability

Organization	Yes or No	Question 7 Comment
		need is especially questionable for Xcel Energy's footprint within WECC, since the inter-regional transfer capability is virtually the same as the Transfer Capability for a WECC Major Path, recognizing that the WECC Major Paths are essentially inter-regional interfaces or cut-planes. Consequently, the SOL computed for a WECC Major Path using the methodology in FAC-010-1 and/or FAC-011-1 is not significantly different than its TTC computed using the MOD-029-1 methodology, or its TC computed using the existing FAC-012-1 methodology. Therefore, the planning horizon TC computed in accordance with draft FAC-013-2 is not expected to result in any new reliability metric for most entities within WECC.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The SDT agrees that In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.		
Tennessee Valley Authority	No	
Tampa Electric Company	Yes	How the PTC is calculated including what assumptions will be made are crucial to determining the value of this requirement to the reliability of the BES
Response: The SDT thanks you for your affirmative response and clarifying comment.		
FPL Transmission Planning	Yes	Yes, if the PTC are truly designed to provide future planning information regarding reliability based capability limitations on the BES, then this standard would have value for improving reliability. Otherwise it would have little or no real value.
Response: The SDT agrees with your comment. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
Progress Energy Florida	Yes	Yes, but only if PTC is made "available for the reliable planning of the Bulk Electric System (BES)" [Purpose, A3]. Otherwise PTC has no applicable purpose.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The standard requires response to written comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy.		

Organization	Yes or No	Question 7 Comment
Florida Municipal Power Agency	Yes	
Beaches Energy Services (of the City of Jacksonville Beach, FL)	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
Georgia Transmission Corporation	Yes	
Manitoba Hydro	Yes	
Duke Energy	Yes	
FMPA	Yes	
Southern Company	Yes	

8. 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: The majority of the negative commentes indicated that the Planning Transfer Capability term should be retired due to the lack of benefits for BES reliability and could cause additional burdens and confusion for the Planning Coordinators. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The TPL standards do not adequately cover the need at this time.

The proposed standard includes a peerreview process, and requires a response to documented comments from parties that have a reliability related need for the PTC assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy.

Several of the negative comments questioned the need for calculating PTC for each year 2 through 5. The standard no longer requires assessments to be performed for each year 2-5; the SDT revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. The calculation of PTC's is no longer a requirement but assessments are expected to be conducted annually.

A couple of the negative comments indicated that the standard was important for the planning of the electric system. The SDT explained that some existing practices may be duplicative of this standard because we believe it is good utility practice. Therefore, the new standard codifies these practices and compliance with the new standard should be more easily achieved.

Organization	Yes or No	Question 8 Comment
Tampa Electric Company		R4 should not require calculating PTC for each year 2-5, only selected years as needed.
Response: The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. Calculation of PTC's is no longer a requirement. Assessments must be conducted annually.		
FPL Transmission Planning		Requirement R4 is unclear about what is meant by "for years two through five" and may be excessive. The requirement should allow for the PTC calculation to be performed on representative year(s) (years two through five) of the near-term planning horizon to capture changes affecting PTC. The requirement can be reworded as follows: "R4. Each planning Coordinator shall verify and, if assumptions or criteria as described in the PTCMD have changed, recalculate its PTCs consistent with its PTCMD for beyond 13 months and

Organization	Yes or No	Question 8 Comment
		representative year(s) of the timeframe through year five (to capture system changes that affect PTC) at least once each calendar year, with no more than 15 months between verifications.”
Response: The SDT agrees that assessments do not need to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon.		
Orlando Utilities Commision		Excellent work on this standard! Several Questions relating to R4: Question 1: By years two through five, is it intended for there to be a rigid frame of reference for year two? As an example is it two years beyond the calendar year you are doing the study? Or is year two expected to line up with year two from your TPL studies? Or is it intended the Planning Coordinator will define the exact reference for years two through five? Question 2: On the day the standard is effective, it’s pretty clear a PTCMD should be in place. However are entities expected to have PTC’s in place, or are they expected to calculate a set that Calendar year, or some other time frame.
Response: The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. Calculation of PTC’s is no longer a requirement. The Planning Coordinator is required to conduct an assessment annually.		
AECI		Requirement 4 should be explained as to clarify exactly what years two through five are needed for the recalculation of PTCs if assumptions and/or criteria have changed. There are not always current regionally coordinated models available for each year two through five, which should be taken into consideration.
Response: The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon.		
Progress Energy Florida		Requirement R4 uses the term “for years two through five”, which is unclear given the differences in how the numbering of years is administered by the various PCs. R4 should include language addressing this issue, perhaps using alternate language as follows: “Each Planning Coordinator shall verify and, if assumptions or criteria as described in Requirement 1 Part 1.1 have changed, recalculate its PTCs consistent with its PTCMD and its particular year-numbering convention for years two through five at least once each calendar year with no more than 15 months between verifications.” Note that the phrase “verify, and if” needs to be changed to “verify and, if” in order for the sentence to be grammatically correct. Measure M2 needs the comma punctuation after “PTCMD” deleted in order for the sentence to be grammatically correct. Finally, we would like to reiterate that FAC-013-2 is being developed as part of the process of planning the

Organization	Yes or No	Question 8 Comment
		BES reliably. While we have suggested that this clarification would be best applied in R1.2, our general point is that this has not been appropriately clarified anywhere in the sub-requirements, and such clarification is necessary somewhere within the Requirements in order for FAC-013-2 to match the intent in the Purpose (A3).
Response: The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. Requirement R4 and Measure M2 have been modified and the grammatical issues you identified no longer exist. The SDT agrees that the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard has been modified accordingly.		
Northeast Power Coordinating Council		o Text box on top of page 3 - Please explain within the document (perhaps even via a footnote) the difference between "Available Transfer Capabilities" and "Available Flowgate Capabilities". o Is there a particular significance to the fact that the document uses the term Limit when referring to System Operating Limits, and the term Capability when referring to Planning Transfer Capabilities? If the terms are deemed equivalent, then only one should be used to avoid confusion. Otherwise, a differentiation should be offered within the document, along with reasons for employing such a distinction.
Response: The PTC term has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC.		
SERC Planning Standards Subcommittee		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The SDT thanks you for your clarifying comment.		
Bonneville Power Administration		Bonneville believes the SDT does not address FERC's intent for modifications to FAC-012 and FAC-013.The SAR, in the 'Brief Description' section the FERC 729 quote provides a link back to FERC Order 693 setting the foundation for what the FAC-012 and FAC-013 standards are to address. This quote links the MOD ATC standards' calculation of transfer capability to the intent of what FERC desired of the modifications to FAC-012 and FAC-013.In the 'Detailed Description' section, FERC Order 729 paragraph 279, the intent of the FAC-012 and FAC-013 modifications is to '...calculate transfer capabilities for use in determining available transfer capability be identical to those used in planning and operating the system'. Also, regarding the Planning Horizon, in paragraph 289 FERC clarifies and is in agreement with NERC that the Planning Horizon

Organization	Yes or No	Question 8 Comment
		is 1 to 5 years.
Response: The SDT believes the draft3 FAC-013-2 meets this directive. The SDT considered the statements in P782 regarding transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. Understanding that even though ATC is not required to be calculated for the Near-Term Transmission Planning Horizon, the team felt any differences in "assumptions and criteria" between normal planning studies (steady state, stability, short circuit) and transfer simulations are consistent and the only differences are those that are technically necessary for the type of stress the transfer simulations place on the bulk power system. These differences are similar to the differences in assumptions and criteria between steady state analysis and stability analysis. The actual directive from P782 regarding transfer capability analysis to be consistent with Order 890 has also been met. The transfer simulation analysis does not treat users of the transmission system differently.		
IRC Standards Review Committee		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for entities to dispute or request modification to the calculation of specific PTC values, which exceptions must then be documented in a revised PTCMD. The requirement to respond to all technical comments and/or revise PTCs and the PTCMD would be a significant administrative burden to the Planning Coordinators. Additionally, it should be noted that the NERC Board of Trustees approved the results-based standards initiative which includes a specific, stated goal to eliminate purely administrative requirements, which R3 is. Finally, FERC Order 890 already contains requirements for transmission planners to have stakeholder process. Accordingly, stakeholders already have a process through which they can address, with Planning Coordinators, issues with values and/or assumptions used in the planning horizon and/or system expansion plans. o Part 2.3 should be either be removed due to its subjective nature or criteria for requesting such data should

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		be added to clarify what entities can request such data, under what circumstances they can do so, and how disputes regarding such requests are to be resolved. More specifically, R3 contains no indication regarding the entity that makes the determination that a functional entity had a reliability-related need to the PTCs. Additionally, there are no dispute resolution provisions to govern disagreements between Planning Coordinators and entities requesting data under R3. Accordingly, the drafting team should either remove R3 from the standard or review the functional entities in the functional model and add the specific entities that should have access to the PTCs.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. R3 has been revised and focuses solely on the methodology – not on any actual calculations. This "peer review" process has been adopted in several other standards. No stakeholder process is mandated, the standards only requires a response to documented comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities. Order 890 processes does not.		
MRO's NERC Standards Review Subcommittee		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for

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ERCOT		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to

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American Transmission		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the

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Company		planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for entities to dispute or request modification to the calculation of specific PTC values, which exceptions must then be documented in a revised PTCMD. The requirement to respond to all technical comments and/or revise PTCs and the PTCMD would be a significant administrative burden to the Planning Coordinators. Additionally, it should be noted that the NERC Board of Trustees approved the results-based standards initiative which includes a specific, stated goal to eliminate purely administrative requirements, which R3 is. Finally, FERC Order 890 already contains requirements for transmission planners to have stakeholder process. Accordingly, stakeholders already have a process through which they can address, with Planning Coordinators, issues with values and/or assumptions used in the planning horizon and/or system expansion plans. Part 2.3 should be either be removed due to its subjective nature or criteria for requesting such data should be added to clarify what entities can request such data, under what circumstances they can do so, and how disputes regarding such requests are to be resolved. More specifically, R3 contains no indication regarding the entity that makes the determination that a functional entity had a reliability-related need to the PTCs. Additionally, there are no dispute resolution provisions to govern disagreements between Planning Coordinators and entities requesting data under R3. Accordingly, the drafting team should either remove R3 from the standard or review the functional entities in the functional model and add the specific entities that should have access to the PTCs.

Response: The standard's emphasis has been revised to focu on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.

The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon.

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Midwest ISO		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for entities to dispute or request modification to the calculation of specific PTC values, which exceptions must then be documented in a revised PTCMD. The requirement to respond to all technical comments and/or revise PTCs and the PTCMD would be a significant administrative burden to the Planning Coordinators. Additionally, it should be noted that the NERC Board of Trustees approved the results-based standards initiative which includes a specific, stated goal to eliminate purely administrative requirements, which R3 is. Finally, FERC Order 890 already contains requirements for transmission planners to have stakeholder process. Accordingly, stakeholders already have a process through which they can address, with Planning Coordinators, issues with values and/or assumptions used in the planning horizon and/or system expansion plans. o Part 2.3 should be either be removed due to its subjective nature or criteria for requesting such data should be added to clarify what entities can request such data, under what circumstances they can do so, and how disputes regarding such requests are to be resolved. More specifically, R3 contains no indication regarding the entity that makes the determination that a functional entity had a reliability-related need to the PTCs. Additionally, there are no dispute resolution provisions to govern disagreements between Planning Coordinators and entities requesting data under R3. Accordingly, the drafting team should either remove R3 from the standard or review the functional entities in the functional model and add the specific entities that

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Kansas City Power & Light		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for entities to dispute or request modification to the calculation of specific PTC values, which exceptions must then be documented in a revised PTCMD. The requirement to respond to all technical comments and/or revise PTCs and the PTCMD would be a significant administrative burden to the Planning Coordinators. Additionally, it should be noted that the NERC Board of Trustees approved the results-based standards initiative which includes a specific, stated goal to eliminate purely administrative requirements, which R3 is. Finally, FERC Order 890 already contains requirements for transmission planners to have stakeholder process. Accordingly, stakeholders already have a process through which they can address, with Planning Coordinators, issues with values and/or assumptions used in the planning horizon and/or system expansion

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LG&E and KU Energy LLC		LG&E and KU Energy LLC support the comments submitted by the Midwest ISO.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. R3 has been revised and focuses solely on the methodology – not on any actual calculations. This "peer review" process has been adopted in several other standards. No stakeholder process is mandated, the standard only requires a response to documented comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities. Order 890 processes does not.		

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Duke Energy		The second to last paragraph in the whitepaper does not illustrate the concept of “as or more limiting” clearly. A better example would be something along the lines of: For example, if N-1-1 contingencies are used for evaluation in the operating horizon, N-1 contingencies could not be used to calculate PTC, because this criterion would be less limiting than what is being used in the operating horizon.
Response: The example has been dropped from the whitepaper because revisions to the standard removed the “as or more limiting” concept.		
East Kentucky Power Cooperative, Inc.		Sub-requirement 1.4 (A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon) is of questionable merit. There may be valid reasons why assumptions and criteria used in the operating horizon may be more limiting than those used in the planning horizon. Each Planning Coordinator should decide what criteria and assumptions are used in the planning horizon vs. the operating horizon without a requirement that the planning horizon is always as, or more, limiting. PTCs are not likely to translate into the operating horizon in any event. This sub-requirement has no positive impact on reliability of the BES.
Response: The SDT agrees and has modified the standard to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator’s planning practices. The standard’s emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
United Illuminating		R1.4 Technical Comment: UI recognizes the intent of R1.4 is to attempt to provide consistency in the calculation between the Planning and Operating Horizon. However there will be instances where the assumptions and criteria used to calculate PTCs can not be as, or more, limiting than the assumptions and criteria used in the operating horizon. This is because the assumptions applicable to the two different horizons must be different due to changes in topology, generation or rules, or just more accurate information. Also, it is difficult to interpret what is meant by more limiting. UI does not believe that reliability requires consistency in the two time horizons.R4 editorial comment: The placement of the commas is incorrect. Does the drafting team mean to “verify and recalculate” or to verify and only recalculate if assumptions changed? Also, it is unclear what is being verified by the PC; is it the PTCMD, or the PTC results? R5 editorial comment. Proposed R5 is The Planning Coordinator shall make its PTCs available no later than 30 calendar days (following the verification or recalculation of those PTCs) to those entities identified in Requirement R2. The information that is in the parenthesis is required to make the requirement sensible. Consider removing the parenthesis.Implementation Plan: First, Can the implementation plan provide clarity for when is the PC required to initially issue the PTCMD to its adjacent PC’s? Second, If the effective date is October 1 (first day, first calendar quarter) is the PC required to complete the R4 annual review in that quarter? Can the implementation plan be modified to move R4 effective date to the calendar year following implementation of R1? Lastly, as written, the PC is only required to calculate PTC per R5 following the verification and

Organization	Yes or No	Question 8 Comment
		recalculation process required in R4 following a change to (not the establishment of) the PTCMD. Is the PC required to calculate PTC per the PTCMD prior to the annual verification? Can the implementation plan be specific?
Response: The SDT agrees that clarification of 1.4 was necessary and has modified the standard to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices. Requirements R4 and R5 have been modified and the grammatical issues no longer exist. The standard has been clarified to require annual assessments. The effective date will be based on when the standard is approved.		
WAPA-RMR		WECC has a process in-place known as the Three-Phase Rating Process that encompasses the Requirements laid out in this proposed FAC-013-2 re-write. FAC-013 will result in a duplicative effort with no resulting increase in realibility in the West. Perhaps the WECC process can be re-written to accomplish meeting the Requirements of the proposed FAC-013-2 under a WECC-driven effort.
Response: Some existing practices may be duplicative of this standard because we believe it is good utility practice. Therefore, compliance with the new standard should be more easily achieved.		
ISO New England Inc.		This standard is not important for planning the electric system.
Response: In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.		
Independent Electricity System Operator		As indicated under Q1, a review of the Comment Report suggests that the majority of the commenters disagree with the need to define the terms PTC and PTCID. We are disappointed that the SDT chose to ignore the majority comments.
Response: Definitions for PTC and PTCID are no longer required.		
Xcel Energy		Should the Purpose statement contain the phrase "forecasts of" even though it was deleted from the PTC definition? Recommend reverting back to the Purpose statement of the existing FAC-012-1 and adapt it for planning time-frame by deleting "and operation" plus "or methodologies." The resulting Purpose will be as follows: "To ensure that Transfer Capabilities used in the reliable planning of the BES are determined based on an established methodology."Requirement R4 requires recalculating TC for "years two through five" but it is unclear what should be considered as year one. Suggest adopting the definition of Near-Term Transmission Planning Horizon from the draft TPL-001-2 (Project 2006-2) and use it in lieu of year numbers.
Response: The word "forecasts" is not necessary in the purpose. The standard's emphasis has been revised to focus on assessment of future reliability and		

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facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon.		