NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on 2nd Draft of Standard MOD-008-1 — Available Transfer Capability (Project 2006-07)

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on First Draft of Standard MOD-008-1 TRM. This SAR was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 19 sets of comments, including comments from 95 different people from more than 45 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders, comments from the cooperative effort with NAESB in developing associated business practices, and comments received from FERC staff, the drafting team has significantly redrafted the standard. The changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- Added a new term, 'Transmission Reliability Margin Implementation Document' that replaces the references to a Transmission Reliability Margin Calculation Methodology
- Expanded the purpose statement
- Eliminated the Transmission Planner, Reliability Coordinator, Planning Coordinator and Load-serving Entity from the applicability section of the standard
- Revised R1 to limit applicability to the Transmission Operator
- Absorbed R2 into R1 and expanded R1 to add more specificity to the documentation the Transmission Operator must have to support its TRM calculation methodology, including new language that:
  - Clarifies that documentation must be provided for each Posted Path or Flowgate
  - Requires that the documentation of the uncertainties used in calculating TRM include maintenance outages and future generation
  - Requires that the documentation of the uncertainties used in calculating TRM include uncertainties regarding frequency bias
  - Requires documentation of the practice if TRM is zero for all time periods rather than requiring why it did not reserve any TRM
  - Added an upper boundary of up to 13 months for the calculation of TRM in the 'beyond day-ahead and pre-schedule' time period
  - Eliminated references (from original R2) to posted Contract Paths
- Modified what had been R3 and R4 (now R2 in the revised standard) to clarify that the uncertainties used in calculating TRM may not include any of the components of CBM
- Modified R5 and merged it with R6, moving the requirement for the Transmission Planner to calculate TRM for the time period beyond the day-ahead and pre-schedule period to the Transmission Operator - and added an outer boundary of 13 months to the 'beyond the day-ahead and pre-schedule' time period.
- Eliminated R7 which required the Transmission Service Provider to make its TRM calculation methodology publicly available – the posting requirements will be addressed in NAESB business practices.
- Modified R8 so that the Transmission Service Provider is only required to provide its TRM Implementation Document and associated documentation to those Transmission

Service Providers who have made a request for the information – the requirement to provide the information to transmission customers and load-serving entities has been removed

- Modified R9 (now R3) to limit applicability to the Transmission Operator and added some words to improve the clarity
- Eliminated R10 as the posting requirements are being addressed by NAESB
- Eliminated R11 which required the Transmission Planner and Transmission Operator that reserved capacity on its transmission system for use as TRM to also use TRM in its ATC or AFC calculations.

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/MOD-V0-Revision.html

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

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

The Industry Segments are:

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

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Jason Murray (G6)	AESO		✓								
2.	Darrell Pace (G3)	Alabama Electric Coop., Inc.				✓	✓	✓				
3.	Anita Lee (G1)	Alberta Electric System Operator		✓								
4.	Helen Stines (G3)	Alcoa Power Generating, Inc.						✓	✓	✓	✓	
5.	Eugene Warnecke (G3)	Ameren	✓		✓			✓				
6.	E. Nick Henery	APPA	✓									
7.	Jerry Smith (G6)	APS-TP										
8.	Steve Tran (G6)	BP TX										
9.	Abbey Nulph (G6) (I)	BPA	✓		✓		✓	✓				
10.	Rebecca Berdahl (G6)	BPA	✓		✓		✓	✓				
11.	Steve Knudsen (G6)	BPA	✓		✓		✓	✓				
12.	Charles Mee (G6)	CA Dept Water & Power										
13.	Brent Kingsford (G1)	California ISO		✓								
14.	Greg Ford (G6)	CISO-TP		✓								
15.	Greg Rowland	Duke Energy	✓		✓							
16.	Don Reichenbach (G3)	Duke Energy	✓		✓		✓	✓				
17.	Narinder K. Saini	Entergy Services, Inc.	✓		✓		✓	✓				
18.	George Bartlett	Entergy Services, Inc.	✓		✓		✓	✓				
19.	Jim Case	Entergy Services, Inc.	✓		✓		✓	✓				
20.	Ed Davis	Entergy Services, Inc.	✓		✓		✓	✓				
21.	Joachim Francois (G3)	Entergy Services, Inc.	✓		✓		✓	✓				
22.	Steve Myers (I) (G1)	ERCOT		✓								
23.	Patricia vanMidde (G6)	FERC Case MRG, Sempra										

24.	Dave Folk	FirstEnergy Corp.	✓		✓		✓	✓				
25.	Richard Kovacs	FirstEnergy Corp. EDPP	✓		✓		✓	✓				
26.	Phil Bowers	FirstEnergy Corp. EDPP	✓		✓		✓	✓				
27.	Ross Kovacs (G3)	Georgia Transmission Corp.	✓		✓							
28.	Roger Champagne	Hydro-Québec TransÉnergie (HQT)	✓									
29.	Danielle Beaulieu	Hydro-Québec TransÉnergie (HQT)	✓									
30.	Daniel Soulier	Hydro-Québec TransÉnergie (HQT)	✓									
31.	Ron Falsetti (I) (G1)	Independent Electricity System Operator (IESO)		✓								
32.	Lou Ann Westerfield (G6)	IPUC-SP										
33.	Matthew F. Goldberg (I) (G1)	ISO New England (ISO-NE)		✓								
34.	Brian Thumm	ITC Transco	✓									
35.	Sueyen McMahon (G6)	LADWP	✓		✓		✓	✓				
36.	Eric Ruskamp (G2)	LES	✓		✓		✓	✓				
37.	Michelle Rheault	Manitoba Hydro	✓		✓		✓	✓				
38.	Jerry Tank (G3)	MEAG	✓		✓		✓					
39.	Dennis Kimm	MidAmerican Energy – Energy/Trading (MEC Trading)			✓		✓	✓				
40.	Tom Mielnik (I) (G2)	MidAmerican Energy Co. (MEC)			✓		✓	✓				
41.	Bill Phillips (G1)	Midwest ISO		✓								
42.	Larry Middleton (G3)	Midwest ISO		✓								
43.	Carol Gerou (G2)	Minnesota Power	✓		✓		✓	✓				
44.	Terry Bilke (G2)	MISO		✓								
45.	Mike Brytowski (G2)	MRO										✓
46.	Matt Schull	NCMPA (with APPA)					✓					
47.	Jim Castle (G1)	New York ISO		✓								
48.	Robert W. Creighton	Nova Scotia Power, Inc. (NPSI)	✓									
49.	Todd Gosnell (G2)	OPPD	✓		✓			✓				
50.	Brian Weber (G6)	Pacificorp	✓				✓					
51.	Alicia Daugherty (G1)	PJM		✓								
52.	Mignon L. Clyburn (G5)	PSC of South Carolina									✓	
53.	G. O'Neal Hamilton (G5)	PSC of South Carolina									✓	
54.	John E. Howard (G5)	PSC of South Carolina									✓	
55.	Randy Mitchell (G5	PSC of South Carolina									✓	

56.	C. Robert Moseley (G5)	PSC of South Carolina									✓	
57.	David A. Wright (G5)	PSC of South Carolina									✓	
58.	Philip Riley (G5)	PSC of South Carolina (PSC SC)									✓	
59.	Chuck Falls (I) (G6)	Salt River Project (SRP)	✓									
60.	John Troha (G3)	SERC										✓
61.	Carter Edge (G3)	SERC										✓
62.	Bob Schwermann (G6)	SMUD	✓		✓		✓	✓				
63.	Brian Jobson (G6)	SMUD	✓		✓		✓	✓				
64.	Dick Buckingham (G6)	SMUD	✓		✓		✓	✓				
65.	Dilip Mahendra (G6)	SMUD	✓		✓		✓	✓				
66.	W. Shannon Black (G6)	SMUD	✓		✓		✓	✓				
67.	Phil Odonnell (G6)	SMUD- Ops	✓		✓		✓	✓				
68.	Al McMeekin (G3)	South Carolina Electric & Gas Co.			✓		✓	✓				
69.	Stan Shealy (G3)	South Carolina Electric & Gas Co.			✓		✓	✓				
70.	JT Wood (G4)	Southern Company Services, Inc.	✓				✓					
71.	Roman Carter (G4)	Southern Company Services, Inc.	✓				✓					
72.	Gary Gorham (G4)	Southern Company Services, Inc.	✓				✓					
73.	Marc Butts (G4)	Southern Company Services, Inc.	✓				✓					
74.	Bill Botters (G4)	Southern Company Services, Inc.	✓				✓					
75.	Ron Carlsen (G4)	Southern Company Services, Inc.	✓				✓					
76.	Jim Howell (G4)	Southern Company Services, Inc.	✓				✓					
77.	Jeremy Bennett (G4)	Southern Company Services, Inc.	✓				✓					
78.	Jim Viikinsalo (G4	Southern Company Services, Inc.	✓				✓					
79.	Reed Edwards (G4)	Southern Company Services, Inc.	✓				✓					
80.	Dean Ulch (G4)	Southern Company Services, Inc.	✓				✓					
81.	Garey Rozier (G4)	Southern Company Services, Inc.	✓				✓					
82.	Karl Moor (G4)	Southern Company Services,	✓				✓					

		Inc.										
83.	Chuck Chakravarthi (G4)	Southern Company Services, Inc.	✓				✓					
84.	DuShaune Carter (G4)	Southern Transmission	✓									
85.	Charles Yeung (G1)	Southwest Power Pool		✓								
86.	Casey Sprouse (G6)	Sr. Term Marketer										
87.	Maria Denton (G6)	SRP										
88.	Terri M. Kuehneman (G6)	SRP System Operation										
89.	Raquel Agular (G6)	Tucson	✓		✓		✓	✓				
90.	Ron Belval (G6)	Tucson	✓		✓		✓	✓				
91.	Jim Haigh (G2)	WAPA									✓	
92.	Raymond Vojdani (G6)	WAPA									✓	
93.	Mike Wells (G6)	WECC										✓
94.	Neal Balu (G2)	WPS			✓		✓	✓				
95.	Pam Oreschnick (G2)	XEL	✓		✓		✓	✓				

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – IRC Standards Review Committee (IRC)
G2 – MRO Members (MRO)
G3 – SERC Available Transfer Capability Working Group (SERC ATCWG)
G4 – Southern Company Services, Inc. (SOCO)
G5 – Public Service Commission of South Carolina (PSC SC)
G6 - WECC MIC MIS ATC Task Force

Index to Questions, Comments, and Responses

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

Summary Consideration: The majority of commenters agreed with the combination. The Standard Drafting Team has redrafted the standard to eliminate the duplication between R1 and R2, as well as clear up some of the confusion and conflicts in regard to responsibilities. Please see the list of major changes made to the standard on the cover page of this report.

Question #1			
Commenter	**Yes**	**No**	**Comment**
IESO IRC SRC	☑	☑	We agree with combining the two standards, but the newly created standards contain quite a few more requirements than MOD-008-0 and MOD-009-0 taken together, and some of the requirements are duplicated (for example, R1 and R2). Also, some requirements are not clear as to who should be responsible, for example: there are conflicting yet sometimes duplicated requirements for documenting and calculating TRM. R1 and R2 hold the TP and TOP responsible for these tasks, yet R8 and R9 hold TSP responsible as well. There needs more clarity particularly in the accountability for documenting the methodology and in providing the supporting basis for determining TRM.
Response: The Standard Drafting Team has redrafted the standard to eliminate the duplication between R1 and R2, as well as clear up some of the confusion and conflicts in regard to responsibilities. Please see the list of major changes made to the standard on the cover page of this report.			
APPA	☑		
Duke Energy	☑		
ERCOT	☑		
FirstEnergy	☑		
ITC	☑		
MEAG	☑		
MEC	☑		
MEC Trading	☑		
Manitoba Hydro	☑		
MRO	☑		
NPSI	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
PSC SC	☑		
SERC ATCWG	☑		
WECC MIC MIS ATC TF	☑		
SOCO	☑		

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

Summary Consideration: While most stakeholders who responded to this question indicated that the SDT has adequately responded to the directives in Order 890 and 693, there were some suggestions for improvement. The SDT has redrafted some parts of the standard to address these stakeholder suggestions.
R1.2 was modified as follows:

R1.2 A statement to confirm that it shall use ~~the same~~ consistent assumptions in calculating TRM as those that are used in the transmission planning process for the appropriate time periods.

R3 and R4 were modified as follows:

R~~3~~2. The ~~Transmission Planner and~~ Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM , and not include any of the components of CBM.

~~R4. The Load-Serving Entity shall not use the components of uncertainty from R1.1 to determine its CBM megawatt import requirement.~~

Question #2			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The SDT has addressed most of the issues in the FERC Orders. However, it is not clear from the Standard that once transmission capacity has been reserved as TRM, under what circumstances can energy be scheduled on TRM transmission Capacity?
Response: The standard drafting team does not believe it is appropriate to specify scheduling requirements in this standard.			
Duke Energy		☑	It is unclear that the drafting team has addressed FERC's direction in paragraph 275 of Order No. 890 to establish appropriate maximum TRM. Perhaps the Standards Drafting Team should consider using the TPL standards requirements as a basis for bounding the maximum TRM value.
Response: The drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the types of uncertainty listed in the standard.			
ITC		☑	Some of the requirements, such as R1.2 and R4 need additional work.
Response: The drafting team has redrafted the standard to address these comments. Please see the list of modifications made to the standard listed on the cover page of this report. Both R1.2 and R4 were modified.			
MEC Trading		☑	This appears to require no consistency and appears to be a fill-in-the-blank standard.
Response: The standard drafting team feels that because different entities experience different amounts of uncertainty,			

Question #2			
Commenter	**Yes**	**No**	**Comment**
flexibility is required in this standard.. For example, some entities experience much larger loop flows through their system than other entities.			
IESO IRC SRC	☑	☑	Most of the directives appear to be addressed. However, in view of the above comments, we expect the standards need more work so a revisit of this question is required.
Response: The Standard Drafting Team has continued to diligently work on the standard and has made numerous change based on comments from stakeholders, NAESB and FERC. Please see the list of modifications made to the standard listed on the cover page of this report.			
ERCOT	☑		
FirstEnergy	☑		
HQT	☑		
MEC	☑		
Manitoba Hydro	☑		
MRO	☑		
PSC SC	☑		
WECC MIC MIS ATC TF	☑		
SOCO	☑		

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why

Summary Consideration: There was no consensus amongst the stakeholders who responded to this question – however several commenters indicated here and elsewhere that the standard should not apply to the Reliability Coordinator or the Planning Coordinator, and the Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard.

Question #3			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The Applicable Reliability Functions are identified; however the standard is requiring those Functions to duplicate their duties in this Standard that is required in other Standards. If this Standard wants to post the results of those duties, then the correct standard must be referenced in lieu of repeating the requirement.
Response: It is not the standard drafting team's intention to repeat requirements in other standards. The drafting team has examined the other reliability standards to check for repeat requirements and found no repeated requirements.			
BPA		☑	"Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority.
Response: Planning Coordinator is the current terminology used in the NERC Functional Model. We will add this definition to the Glossary. Note that the Standards Committee directed all drafting teams to begin using the term, 'Planning Coordinator' in the drafting of reliability standards.			
Duke Energy		☑	This standard shouldn't be applicable to the Reliability Coordinator because this is a calculation methodology, and Reliability Coordination is a real-time role. Also, it is unclear which requirements of this standard apply to the Planning Coordinator. Unless specific roles in TRM determination are identified for the Reliability Coordinator and Planning Coordinator, they should be deleted from the Applicability section.
Response: The Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard			
ERCOT		☑	There is no requirement applicable to Reliability Coordinator or Planning Coordinator. Therefore, MOD-008-1 should not be applicable to Reliability Coordinator and Planning Coordinator.
Response: The Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard.			
IESO IRC SRC		☑	We do not think the standard clearly conveys the accountability of each of the responsibility entities well enough. Please see our comments to Q1 above. In addition, we feel that the entire set of MOD-001, -004, -008, -028, -029 and -30 lacks clarity in

Question #3			
Commenter	**Yes**	**No**	**Comment**
			responsibility. For example, the RC and PC should not be responsible for calculating ATC. Why would they be included in the applicability section of some standards/requirements?
Response: The standard drafting team has identified, for each requirement, the entity accountable for carrying out that requirement. Note that the applicability section of the standard was revised, and the standard no longer has any requirements applicable to the Planning Coordinator or the Reliability Coordinator.			
MEC MEC Trading		☑	The Planning Coordinator and the Reliability Coordinator should have some role in this standard. They are listed as applicable Functional Entities that the standard is applicable yet they are not listed as the subject of any requirement.
Response: The Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard. They are recipients of some of the products, but they are not assigned accountability for any requirements.			
MRO		☑	The MRO believes that the Planning Coordinator and the Reliability Coordinator should have some role in this standard. They are listed as applicable Functional Entities that the standard is applicable yet they are not listed as the subject of any requirement.
Response: The Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard. They are recipients of some of the products, but they are not assigned accountability for any requirements.			
ITC	☑	☑	For once, the Reliability Coordinator may be an appropriate entity in these standards. TRM is addressing uncertainty. A real-time operator will be more aware of actual system uncertainties than most people, including planners. "Loopflow" has proven to an elusive animal to keep track of. TRM for loopflow is an important parameter. The RC should have input here.
Response: The SDT agrees that a real-time operator will have first hand knowledge of actual system uncertainties, which is why the Transmission Operator was included in the applicability of the standard. The SDT reviewed the standard and the functional model and did not assign any requirements to the Reliability Coordinator.			
FirstEnergy	☑		
MEAG	☑		
Manitoba Hydro	☑		
PSC SC	☑		
WECC MIC MIS ATC TF	☑		No comment.
SOCO	☑		

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

Summary Consideration: Several stakeholders suggested modifying or deleting some of the requirements in the first draft of the standard. Based on stakeholder comments, the SDT has deleted R2, and the language in R1 was modified to address R2's deletion as shown below (text highlighted in yellow was in both R1 and R2 in the last draft of the standard – text highlighted in red was added based on stakeholder comments or to better meet the FERC directives):

R1.1. Identification ~~any~~ of (on each of its respective Posted Paths or Flowgates) each of the following components of uncertaint~~ies~~y if used to calculate ~~its~~ a TRM value:

- Aggregate Load forecast ~~error~~ uncertainty (not included in determining generation reliability requirements).
- Load distribution ~~error~~ uncertainty.
- Forecast uncertainty in transmission system topology (including maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions
- Variations in generation dispatch (including maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response and frequency bias.

Based on stakeholder comments, the SDT has rewritten R3 and eliminated R4 from the standard as shown below (now combined into R2 in the revised standard):

R~~3~~2. The ~~Transmission Planner and~~ Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM , and not include any of the components of CBM.

~~R4. The Load-Serving Entity shall not use the components of uncertainty from R1.1 to determine its CBM megawatt import requirement.~~

Question #4			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The standard is requiring Applicable Functions to duplicate their duties in this Standard that are required in other Standards. This Standard as written created duplication of same actions in two different and will cause confusion within the Compliance Program. R 1.1 and R 2 seem to say the

Question #4			
Commenter	**Yes**	**No**	**Comment**
			same thing. This Standard should not set or limit the ways a Planner will determine uncertainty in their in their calculations. It should require that all factors used to determine its uncertainty is provided, but do not set or limit the possibilities. This Standard's scope for TRM does not include the authority to determine study methods.
Response: It is not the standard drafting team's intention to repeat requirements in other standards. We have examined the other reliability standards to check for duplicate requirements, and found none. The Standard Drafting Team agrees there is some redundancy in Requirement R1 and Requirement R2, and revised the standard by merging R1 and R2 into a single requirement, eliminating the redundancy. In order to obtain consistency between the different TRM calculation methodologies we have limited the types of uncertainty that can be used in a TRM calculation. The revised standard does not limit the study methods used in calculating the different types of uncertainty.			
BPA		☑	R1.3. should read "The description of the method of allocation across Posted Paths or Flowgates" where Posted Path is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. R2. -- The parenthetical statement should read "…on each of its respective Posted Paths or Flowgates..." R5. and R6. -- The term "path" should be replaced with "Posted Path". R10. -- The term "posted path" should be capitalized.
Response: The standard drafting team has implemented the suggested changes and they are reflected in the revised standard.			
Duke Energy		☑	There is no requirement for coordination between the Transmission Operator and the Transmission Planner. Also, there should be a requirement that the TRM values should be equal to or lower than long-term TRM as you move closer to real-time and uncertainty diminishes.
Response: The standard drafting team revised the standard to require Transmission Operator calculate TRM and for the Transmission Operator to provide the TRM values to the Transmission Planner. The standard drafting team feels that these modifications address Duke Energy's concerns.			
ERCOT		☑	It is not clear if the intent of R2 is to document component of uncertainty on TRM on each posted path, or a general process to include impact of uncertainties in TRM methodologies is sufficient. The requirement should clarify such that the impact of uncertainties are included in TRM methodologies and not to document each component. R4 is written as a requirement for CBM methodology rather than for TRM methodology, it should be deleted or reworded.
Response: The SDT has deleted R2, and the language in R1 was modified to address R2's deletion. We have included this requirement such that the different assumptions used in determining TRM across your system can be understood. The intent is for the information to be posted for each posted path or flowgate, as stated in the requirement.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
Upon examining R4, we have rewritten R3 and eliminated R4 from the standard. (See R2 in the revised standard.)			
HQT		☑	Variations in facility loading should be back in the R1.1 list
Response: We have updated the language to replace "error" with "uncertainty," which we believe should address your concern. We also believe "Variation in Generation Dispatch" will address this. The drafting team believes that R1.1 contains the components that will cause variations in facility loadings, so adding this would be redundant.			
IESO IRC SRC		☑	There are a number of duplicated requirements (e.g. R1 and R2 as noted above_) and there is no clarity on the accountability (e.g. R9). The standard needs to be reviewed and revised to more clearly convey the roles and responsibilities in accordance with the functional model and today's practice (on a functional entity basis).
Response: There were some redundancies in Requirement R1 and Requirement R2, which have been addressed with new language. R2 was eliminated as a separate requirement, and was merged into R1. R9 was modified (now R3) to limit applicability to the Transmission Operator and added some words to improve the clarity			
ITC	☑	☑	This is a difficult question to answer but easily "measured". TRM is dealing with uncertainty so you're guessing at whatever you do. However, the ultimate real-time system response is your "test result" to see if you picked an appropriate TRM. If no one is denied service and there are no TLRs or congestion, you're right. If there are no or few TSR denials, and congestion or TLRs are persistent, the TRM is probably too low. If TSR is being denied and there is no evidence of congestion or TLR (level 3 for non-firm), TRM might be too high.
Response: This could be an approach to validate the calculated TRM but it is something that may not belong in the TRM requirements (but perhaps in measures and compliance).			
MEC Trading		☑	Again, this still seems like a fill-in-the-blank standard.
Response: Because different entities experience different amount of uncertainty, flexibility is required in this standard in order to account it in each area. For example, some entities experience much larger loop flows through their system than other entities.			
WECC MIC MIS ATC TF		☑	First, the "Applicability" section uses the term "Planning Coordinator" which is not a defined term in the NERC Glossary. If the NERC Team intends it use, it should become a defined term. Second, where the term Planning Coordinator is used, WECC queries whether or not the more accurate entity would be the Transmission Planner.
Response: Planning Coordinator is current terminology used in the NERC Functional Model and the drafting team is taking steps to add this to the NERC Glossary. However, the standard drafting team did revise the applicability section of the standard to address other industry comments suggesting that the standard should not be applicable to the Planning Coordinator, and the standard was revised so that there are no requirements applicable to the Planning Coordinator.			
MRO MEC	☑	☑	1. R1.2 should be revised to indicated that "A statement to confirm that it shall be used CONSISTENT assumptions in calculating TRM.." Same assumptions implies an exactness which is not appropriate and is not required by FERC Order 890.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			2. Makes revisions to R1.1 and R2 per MRO comments provided in response to Question 8 below.
Response: The standard drafting team modified the standard in support of your suggestion, and the revised standard R1.2 uses the phrase, 'consistent assumptions'. Please see the response to your comments on Question 8.			
Manitoba Hydro	☑		
FirstEnergy	☑		
MEAG	☑		
PSC SC	☑		
SERC ATCWG	☑		
SOCO	☑		

5. Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

Summary Consideration: The majority of commenters did not believe that a study should be required. The drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the types of uncertainty listed in the standard.

Question #5			
Commenter	**Yes**	**No**	**Comment**
PSC SC			Our comments are from a regulatory perspective. This is strictly a technical issue.
APPA		☑	This Standard should only require the TRM value be provided and the associated assumptions for determine the amount of error in the planning or operating studies.
Response: The standard drafting team feels that in order to obtain some consistency in TRM calculations we should define the types of uncertainty that can be used to determine TRM.			
BPA		☑	Please clarify that the uncertainties listed in R1.1 may be used in TRM calculations (as opposed to being required to be used).
Response: The standard currently states that the information must be provided only "if used."			
IESO IRC SRC		☑	We do not believe any maximum values should be set as a standard. Individual TSP (or TP and TOP according to the proposed standard) should each determine the amount needed to cover transmission uncertainties, which may vary among systems. The validity of the calculated values can be assessed against the documented methodology and audit process.
Response: The drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the types of uncertainty listed in the standard.			
MEAG		☑	Once the determination of TRM methodology has been identified, the TSP or TP or TC should use it to determine the required TRM values. It should not be required to perform many other studies to determine a TRM with the "maximum uncerttainty".
Response: We agree. The standard drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the chosen types of uncertainty from the list in the standard per the entity's TRM methodology.			
MEC MRO		☑	These studies should be coordinated as a NERC-wide activity outside of these standards.
Response: The standard drafting team appreciates the concern, and will request the Planning Committee develop a white-paper to provide the industry guidance on how to calculate TRM and uncertainty.			
Manitoba Hydro		☑	I don't know what the value of a maximum uncertainty would be. Each uncertainty has a probabalitic component to it. It would be simple enough to add up all the uncertainites but if the probalistic analysis determined that the maximum uncertainty event was once every 10 years or once every 15 years, I do not know what value that would have. If the standard listed some assumptions, e.g. events that you expect to see within a 1 year or 3 year time frame, then this analysis could become more meaningful.

Question #5			
Commenter	**Yes**	**No**	**Comment**
Response: The standard drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the chosen types of uncertainty from the list in the standard per the entity's TRM methodology.			
SOCO		☑	
Duke Energy		☑	
FirstEnergy		☑	
MEC Trading		☑	
NPSI		☑	
SERC ATCWG		☑	Once the determination of TRM methodology has been identified, the TSP or TP or TC should use it to determine the required TRM values. It should not be required to perform many other studies to determine a TRM with the "maximum uncertainty".
Response: We agree. The standard drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the chosen types of uncertainty from the list in the standard per the entity's TRM methodology.			
ITC	☑	☑	You only need to investigate TRM if there is evidence of overselling or underselling. The compliance monitor should be so instructed. TRM is dealing with uncertainty. How do you study uncertainty? You don't, you just observe it in real-time.
Response: Underselling and overselling is not covered by this standard; NERC is focused on ensuring that the TRM is calculated as the Transmission Operator has described in the methodology. Concerns regarding the actual values will need to be pursued through other venues. The standard drafting team believes some of this may be addressed in measures and compliance. We feel that it is possible for entities to calculate the amount of exposure to uncertainty they will experience and use those calculations to determine the amount of TRM they require to maintain reliability.			
ERCOT	☑		Study should include using historic data to determine impact of actual versus forecasted information on loading of transmission system components that are limiting the TTCs or TFCs.
Response: The majority of commenters did not believe that a study should be required. Using historic data to determine the impact of actual versus forecasted information on loading of transmission system could be a valid method for determining the amount of uncertainty due to aggregate load forecast error.			

6. Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

Summary Consideration: Stakeholders who responded to this question indicated that the standard should not preclude nor require that a percentage of Facility Ratings be reserved as TRM. The standard drafting team believes that as long as the TRM is calculated based on the different types of uncertainty listed in R1.1 then it does not matter how that TRM is applied i.e. across interfaces or as a percentage of Facility Ratings. The proposed standard allows each entity to determine the appropriate TRM values for its own system.

Question #6			
Commenter	**Yes**	**No**	**Comment**
PSC SC			Our comments are from a regulatory perspective. This is strictly a technical issue.
Manitoba Hydro			I think that a percentage could be appropriate, but the best TRM value will always be one that is based on analysis of the potential uncertainties on a flowgate. I would hope that the committee will consider using a percentage as a default methodology, but allow for an analysis of uncertainties to modify the final value. A percentage would have to be based on flowgate capability. 5% may be a good default on a 100MW flowgate but overkil on a 1600MW flowgate.
Response: As long as the TRM is calculated based on the different types of uncertainty listed in R1.1 then it does not matter how that TRM is applied i.e. across interfaces or as a percentage of facility ratings. The proposed standard allows each entity to determine the appropriate TRM values for its own system.			
ERCOT		☑	There is no technical justification of using 2 - 5% of Facility Rating as TRM. Since Facility Ratings are determined using conditions that are already worst case conditions, using additional safety factor results in underutilizing the transmission system. If uncertainties such as using first contingency conditions and using worst case scenarios for components that are used for ATC/AFC calculations already include uncertainties there should not be double counting of these uncertainties. If data can be supported by historic information, then only data should be used for setting aside TRM.
Response: The standard drafting team disagrees. We feel that TRM as a percentage of facility ratings is just as quantifiable as TRM across interfaces. Therefore even if an entity uses percentages of Facility Ratings as TRM they must still explain and provide the assumptions they used to arrive at the percentage value.			
HQT		☑	TRM depends on system and path topology.
Response: The standard drafting team disagrees. We feel TRM depends on the different types of uncertainty that the system is exposed to. Therefore any of the different types of uncertainty listed in R1.1 can be used to determine TRM not just system and path topology.			
IESO IRC SRC		☑	We do not believe this approach duly addresses the various components of TRM which may change depending on the system conditions. However, we hold no position on individual entities who choose to apply this approach to determine the TRM.
Response: The standard drafting team feels that the different types of uncertainty outlined in the standard adequately			

Question #6			
Commenter	**Yes**	**No**	**Comment**
addresses the various components of uncertainty that a system would be exposed to. Therefore in order to maintain consistency between transmission systems, the types of uncertainty defined in R1.1 are the only components that can be used to determine a system's TRM.			
MEC MRO		☑	No - some of the area Transmission Service Providers use a percentage and also provide for incremental power flows for reserve sharing.
Response: The TRM standard will continue to allow entities to use a percentage of facility ratings as TRM as long as they arrived at that percentage by using the different types of uncertainty listed in R1.1 which includes reserve sharing agreement.			
FirstEnergy		☑	
MEAG		☑	
NPSI		☑	
SERC ATCWG		☑	
SOCO		☑	
APPA	☑		If a percentage is used then it should be asked of the industry how large of a percentage is permitted before having to explain or provide the assumptions to arrive at the percent value.
Response: In general, we agree. However, we feel that TRM as a percentage of facility ratings is just as quantifiable as TRM across interfaces. Therefore even if an entity uses percentages of Facility Ratings as TRM they must still explain and provide the assumptions they used to arrive at the percentage value.			
BPA	☑		While this methodology may be sufficient for several Transmission Service Providers (TSPs), it may not be for others. Therefore, use of this type of percentage should not be the only mechanism available for TSPs to determine TRM on their systems.
Response: The standard drafting team agrees. We feel that using a percentage of facility ratings is a valid way to account for uncertainty but by no means is the only way to account for uncertainty.			
ITC	☑		5% is appropriate. However, as we have stated before, it could change with observed system response. If you are using 5% and denying service with no TLRs or congestion, you may want to lower it. Compliance monitoring of this standard should (must) include this type of evaluation. Just picking a number only works if the real-time system response justifies it.
Response: The standard drafting team feels that TRM as a percentage of facility ratings is quantifiable by using the different types of uncertainty listed in R1.1. Therefore by calculating the uncertainty exposure each entity will arrive on the appropriate TRM value for its own system. The standard drafting team feels that monitoring TLRs or congestion on the system may be valid a way to validate TRM values but it is not necessarily the only way.			
WECC MIC MIS ATC TF	☑		Two to five percent is acceptable. However, it should not be mandated as the single methodology allowed. Further, the TRM has multiple components, one of which is the Reserve Sharing Group component. The 2-5% is not appropriately applied to the Reserve Sharing Group subset of TRM;

Question #6			
Commenter	**Yes**	**No**	**Comment**
			rather, the 2-5% accurately applies only to the "uncertainty" portion of the TRM. While this methodology may be sufficient for several TSPs, it may not be sufficient for others. Therefore, use of this type of percentage should not be the only mechanism available for TSPs to determine TRM on their systems.
Response: The standard drafting team had decided that as long as the TRM is calculated based on the different types of uncertainty listed in R1.1 then it does not matter how that TRM is applied i.e. across interfaces or as a percentage of facility ratings. We have also decided to let each entity to determine the appropriate TRM values for their own system.			
Duke Energy	☑		

7. Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

Summary Consideration: The drafting team has modified this requirement to more closely align with what is explicitly described in the pro-forma tariff section (attachment C paragraph D) of 890. R1.5 was modified as shown below:

R1.5 If a ~~Transmission Planner or~~ Transmission Operator elects to utilize a TRM of ~~reserves~~ zero ~~(0) TRM in any~~ for all the time periods listed in R1.4 above, ~~time horizon,~~ that ~~Transmission Planner or~~ Transmission Operator shall ~~document~~ include a statement of that practice in its TRM ID ~~methodology the reason(s) why it did not reserve any TRM~~.

Question #7			
Commenter	**Yes**	**No**	**Comment**
PSC SC			Our comments are from a regulatory perspective. This is strictly a technical issue.
BPA			BPA may not calculate TRM on some of its constraints due to uncertainty components being included in those constraints' TFC determinations. Therefore, a TRM of "0 MW" would be posted and documented, per R1.5. of MOD-008-1. Would this practice meet the intent of this standard?
Response: We believe the answer to be yes, but compliance would have the final say. However if you have any suggestions how to make the requirement more clear, please provide them to the group.			
APPA		☑	A zero TRM will provide more ATC for the use by the Transmission Customers. To make the TP or TOP post the reason they have determined that zero is the number is busy work and against good reliable practices.
Response: See summary consideration.			
ERCOT		☑	R1.5 tends to imply that all Transmission Planner and Transmission Operators must use TRM, unless they can justify not using it. On the contrary, those TPs and TOs who use TRM should justify its use as use of TRM results in lower ATCs due to uncertainties that may already be included in determining the components that are used for ATC calculations.
Response: See summary consideration.			
HQT		☑	TP or TO should only explain why it reserves non-zero TRM since it reduces the available capacity for the market.
Response: See summary consideration.			
NPSI		☑	Explaination may divulge commercially sensitive or critical infrastructure information.
Response: See summary consideration.			
SOCO		☑	It is unclear what benefit would be gained by requiring the Transmission Planner or Transmission Operator to supply this explanation.
Response: See summary consideration.			
SRP		☑	This is unnecessary "busy work." FERC is concerned about TSP's hoarding transmission capacity by unjustifiably setting aside large quantities of TRM. If I set aside zero TRM this should make FERC

Question #7			
Commenter	**Yes**	**No**	**Comment**
			very happy because it frees up more ATC for purchase. By making me justify why I am setting aside zero TRM I am being encouraging to set aside non-zero TRM to avoid having to justify it. At the very least R1.5 should be rewritten to clarify precisely what circumstance require justification for zero TRM. For example, if I set aside zero TRM for only one hour on only one path do I have to explain why? Conversely, if I have zero TRM for all time periods and for all paths but one have I avoided the need to justfy why I have zero TRM for the other paths?
Response: See summary consideration.			
IESO IRC SRC	☑	☑	If a 0 MW TRM is reserved, it suggests that the TP and TOP are comfortable with the available control actions other than utilizing the transmission service reserved for TRM to address transmission uncertainties. On the other hand, the value of TRM reserved, including 0 MW, are subject to verification if need be. The question then becomes why 0 MW needs to be explained but not any other values? For example, other transmission users may question a high value of TRM reserved which reduces the ATC for use by others.
Response: See summary consideration.			
FirstEnergy	☑		This explanation increases tranparency in the calculation process which is desired by FERC.
Response: See summary consideration.			
Duke Energy	☑		The explanation should describe how reliability is maintained in light of the uncertainties identified in R1.1
Response: See summary consideration.			
ITC	☑		The justification is simple, no TLRs are observed and no market congestion is observed. If either symtom is present, TRM of zero is not justifiable. I.e, R1.5 is very easy to comply with.
Response: See summary consideration.			
MEC	☑		Generally zero TRM is potentially providing inadequate protection for reliability.
Response: The standard drafting team feels that not all systems require the use of TRM, due to the fact that elements of uncertainty can be accounted for elsewhere in the calculation of ATC/TTC or AFC/TFC.			
MEC Trading	☑		The reason for TRM is uncertainty. It is hard to believe that all of the ATC calculations are without uncertainty, so if uncertainty is buried in another part of the ATC calculation, it would be helpful to know where.
Response: See summary consideration.			
Manitoba Hydro	☑		The analysis need not be extensive and based on past performance, however a 0 TRM allows the tranmission custmers access to a flowgate with no margin of error, and some thought should be put into that situation.
Response: The standard drafting team feels that not all systems require the use of TRM, due to the fact that elements of uncertainty can be accounted for elsewhere in the calculation of ATC/TTC or AFC/TFC.			
MRO	☑		The MRO generally considers zero TRM as potentially providing inadequate protection for reliability.

Question #7			
Commenter	**Yes**	**No**	**Comment**
Response: The standard drafting team feels that not all systems require the use of TRM, due to the fact that elements of uncertainty can be accounted for elsewhere in the calculation of ATC/TTC or AFC/TFC.			
SERC ATCWG	☑		

8. Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

Summary Consideration: None of the stakeholders who responded to this question identified other legitimate neds for TRM that should be described in R1. However, some stakeholders did recommend modifications to the list of uncertainties that must be documented. The standard drafting team has modified R1 to address stakeholder comments suggesting that the list of uncertainties should be expanded to include maintenance outages and the location of future generation. The other items proposed are either already addressed as written, or are addressed in other standards.

Question #8			
Commenter	**Yes**	**No**	**Comment**
NPSI			In the case of a system that is radially connected to other systems via a single interconnection will become islanded for a single contingency (loss of the interconnection). If the system was importing more than 10% (nominal) of its load at the time of the interconnection, the system will likely trigger Stage 1 under frequency load shedding. Therefore there must be a TRM facto that varies with system load to limit the amount of UFLS. In Nova Scotia, we set the import limit at 22% of total net load on our system to avoid Stage 2 UFLS for a single contingency. We use TRM as that variable (with additional margin for load forecast uncertainty. It is not clear if this need is addressed in this standard. Another need would be to share load following with our neighbour (AGC margin). For example, if NS and NB are jointly controlling the NB-New England tie, the NS-NB tie capacity must be held back from its TTC to allow room to respond to load and generation fluctuations (especially wind generation). The latter may be the intent of the R2 "Variations in generation dispatch".
Response: We believe that this should be handled more appropriately as an SOL that impacts the calculation of TTC, rather than including it in TRM. If there are concerns with equity and commercial needs, they would need to be addressed via NAESB business practices or coordination/allocation agreements.			
IESO IRC SRC		☑	None, but there appears to be two requirements that pertain to access to external generation that may be duplicated or in excess of the CBM value: they are aggregate load forecast error and reserve sharing requirements. We suggest the SDT to review the two lists to eliminate any duplication or excessive allocation.
Response: These are not duplicate values. Requirements 3.1.2, 3.2.1, and 3.3.1 of MOD 4 are intended to address the CBM/reserve sharing issue. Regarding Load Forecast error, there are different kinds of load forecast error – one is the operating (day to day) error, which should be used in TRM; the other is long-term error, which is used in generation planning and CBM.			
WECC MIC MIS ATC TF		☑	However, the NERC Team should clarify that the uncertainties listed in R1.1 "may" be used in TRM calculations (as opposed to being required to be used).
Response: These are the only types of uncertainties that can be used in a TRM calculation. The language as written requires "Identification of (on each of its respective Posted Paths or Flowgates) each of the following components of uncertainty *if used* in calculating TRM," which we believe allows for the option to not use.			
Duke Energy		☑	

Question #8			
Commenter	**Yes**	**No**	**Comment**
ERCOT		☑	
FirstEnergy		☑	
MEC Trading		☑	
MEAG		☑	
PSC SC		☑	
SOCO		☑	
ITC	☑	☑	We're dealing with uncertainty here. What is legitimate uncertainty? There are enough requirements to find something to use.
Response: Legitimate uncertainty is the uncertainty we list in R1.1. We agree that there are enough types of uncertainty to choose from in order to satisfy everyone's needs to account for their exposure to uncertainty.			
APPA	☑		The SDT has not made it clear when energy can be scheduled on TRM capacity.
Response: In general, TRM is not scheduled upon except in the case of reserves sharing (in which case it is tagged after the fact) or unless the TRM has been posted back as non-firm.			
HQT	☑		1. Variation of load (for daily, weekly, monthly and yearly ATCs) 2. Uncertainty about weather conditions (for daily, weekly, monthly and yearly ATCs) 3. Variation in facility loading (sufficient TRM should be maintained for deviations from load forecast due to balancing of generation within a control area) 4. Calculation Inaccuracies (Sufficient TRM should be assumed to account for the limitation of the TTC calculation method.)
Response: These uncertainties are accounted for in the present list of uncertainties.			
MEC	☑		Maintenance Outages, Uncertainty in Location of future generation, and uncertainty in power transactions. Also, the Standards Drafting Team should clarify that the Reserve sharing requirements are "Incremental power flows for reserve sharing requirements or automatic sharing of reserves."
Response: The standard drafting team has made modifications to R1.1 to modify 'Variations in generation dispatch' to now state, 'Variations in generation dispatch (including maintenance outages and location of future generation' in support of your suggestion. The other items we believe are already addressed as written.			
Manitoba Hydro	☑		I believe that the need to hold back TRM for Inertial response is broad enough. Just as system load can degrade inertial response, system loading can degrade voltage response. I would recommend that initertial response be changed to include transient, dynamic, and voltage response.
Response: The uncertainty element of transient, dynamic, and voltage response variables should be covered under FAC-			

Question #8			
Commenter	**Yes**	**No**	**Comment**
010.			
MRO	☑		Maintenance Outages, Uncertainty in Location of future generation, and uncertainty in power transactions. Also, the MRO requests that the Standards Drafting Team clarify that the Reserve sharing requirements are "Incremental power flows for reserve sharing requirements or automatic sharing of reserves."
Response: The standard drafting team has made modifications to address the concerns related to outages and future generation. The other items we believe are already addressed as written.			
SERC ATCWG	☑		

9. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

Summary Consideration: The majority of commenters did not have concerns. The SDT notes that some entities may elect to pursue regional differences.

Question #9			
Commenter	**Yes**	**No**	**Comment**
IESO		☑	None, but it should be noted that some entities do not provide physical transmission services and therefore some of the requirements in this standard may not be applicable to them.
Response: The SDT understands your concerns, and notes that entities may elect to pursue regional differences.			
IRC SRC		☑	None, but it should be noted that some entities do not provide physical transmission services and therefore some of the requirements in this standard may not be applicable to them.
Response: The SDT understands your concerns, and notes that entities may elect to pursue regional differences.			
NPSI	☑	☑	Tariffs and Market Rules may have to be updated to reflect the new requirements of MOD-008.
Response: We understand that some entities may need to make such changes.			
MEC Trading	☑		This appears to be a fill-in-the-blank standard.
Response: Because different entities experience different amount of uncertainty, flexibility is required in this standard in order to account it in each area. For example, some entities experience much larger loop flows through their system than other entities.			
Duke Energy		☑	
ERCOT		☑	
FirstEnergy		☑	
ITC		☑	
MEC		☑	
Manitoba Hydro		☑	
MRO		☑	
PSC SC		☑	
WECC MIC MIS ATC TF		☑	
SOCO		☑	

10. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Summary Consideration: Based on stakeholder comments, the drafting team made the following modifications to the standard:

- Removed the requirements to make documents publicly available (R7 and R10). The drafting team has been working closely with NAESB and NAESB confirmed it will address all posting requirements in its business practices
- Removed R4 which required the Load-serving Entity to refrain from using the components of uncertainty identified in the determination of TRM to determine the Load-serving Entity's CBM MW import requirement. If a requirement is needed for this, that requirement should be in the standard covering CBM (MOD-004)
- Modified R8 (R4 in the revised standard) to be more explicit in who it applies to and the method of requesting the information
- Revised the Purpose statement by replacing the phrase "to help ensure more accurate calculation of transfer capabilities" with "for reliable system operations"
- Corrected the typographical error in R1.1 to add the missing word, 'of' after the word, 'Identification'
- Added the words, 'of a documented request' to R8 (R4 in the revised standard)
- Adopted the proposed definition of 'Posted Path' which is already used by FERC
- Added the word, 'Posted' in R5 to change 'Path' to 'Posted Path'
- Absorbed R2 into R1 and eliminated the reference to 'Contract Path'
- Deleted R11

Question #10	
Commenter	**Comment**
Duke Energy	The "make publically available" Requirements R7 and R10 are inappropriate for NERC standards. These are communications which should be in the NAESB standards.
Response: The standard drafting team did work with NAESB and determined that all of the posting requirements will be in NAESB business practices. The drafting team removed Requirement 10 (which required the Transmission Service Provider to make its TRM values publicly available) from the revised standard.	
FirstEnergy	R4 is contained in the revised MOD-004-1 provided with this SAR packet as R14. R4 us a duplicate requirement and should be deleted from MOD-008-1. The request referenced in R8 shoud be required to be in writing as a means of formally documenting the request was made, received, and acknowledged.
Response: The standard drafting team has deleted R4 from this standard. We have modified R8 to be more explicit in who it applies to and the method of requesting the information. The revised requirement (R4 in the revised standard) uses the phrase, '. . . within seven calendar days of a documented request for such information. . ' in support of your suggestion.	

Question #10	
Commenter	**Comment**
IESO	Requirement 1.1 should not only include generation dispatch variations but also peak and off peak dispatch variations. Additionally, Requirement 1.1 – the first line "Identification any of the following…" should be written to read as "Identification of any of the following…" We have provided similar comments on the supplementary SAR, MOD-001 and MOD-004. The SAR for revising and creating this set of standards has not gone through prior public review and comment on the need and direction for these standards. It is posted simultaneously with the revised standard, making posting of the SAR irrelevant. Yet the revised standards appear to be uncoordinated, duplicated and convoluted in some. We understand these standards need to be revised to meet the FERC's timeline but they should be done in a proper and orderly manner to ensure manageability not just by the staff and the SDT but also by the stakeholders in the industry. We do not agree with the process, and we do have trouble reviewing the set of standards that in our view are not well structured (for example: combining all 4 standards MOD-004 to MOD-007 into one). There has been no industry input process that either supports or disagrees with this proposed combining before the standards are drafted and posted. And some of the standards assign responsibilities to entities that should not be responsible for some of the tasks. For example, the RC and PC are not responsible for calculating ATC. The proposed intent to combine some of the MODs as one includes the RC and PC in these standards because of the TTC calculation requirements. But in doing so, the assignment of tasks and responsibilities becomes confusing resulting in these entities being assigned some tasks inappropriately. We suggest the SDT to revise the supplementary SAR and post it for comments, with sufficient detail and specificity on the proposed scope and structure of the standard set, before drafting/revising the standards.

Response:

We believe that "peak and off peak dispatch variations" are covered already in generation and load variations.

We changed R1.1 to "identification of … each of the following".

We recognize the concern expressed by the IESO related to the SAR. However, we are attempting to both address the needs of the industry and the need to comply with the FERC Order, and felt this was the best way to meet both the requirements of the NERC process and be responsive to the Commission. Note that a SAR sets the scope of the technical content of the work, but leaves the structure of the actual standards to the Drafting Team's discretion. The Reliability Standards Development Procedure does allow the simultaneous posting of a SAR and its associated standard or standards.

The drafting team refined the applicability of each standard, based on stakeholder comments and a thorough review of the latest approved version of the Functional Model, and there were several places where the applicability was revised to eliminate the Planning Coordinator and Reliability Coordinator. The drafting team has revised the standards to state more explicitly which functional entity is responsible for each requirement.
Most stakeholders who commented on the SAR indicated support for the SAR as written so the drafting team did not make

Question #10	
Commenter	**Comment**
significant changes to the SAR. The comments on the SAR and the drafting team's responses to those comments have been publicly posted.	
IRC SRC	We have provided similar comments on the supplementary SAR, MOD-001 and MOD-004. The SAR for revising and creating this set of standards has not gone through prior public review and comment on the need and direction for these standards. It is posted simultaneously with the revised standard, making posting of the SAR irrelevant. Yet the revised standards appear to be uncoordinaed, duplicated and convoluted in some. We understand these standards need to be revised to meet the FERC's timeline but they should be done in a proper and orderly manner to ensure manageability not just by the staff and the SDT but also by the stakeholders in the industry. We do not agree with the process, and we do have trouble reviewing the set of standards that in our view are not well structured (for example: combining all 4 standards MOD-004 to MOD-007 into one). There has been no industry input process that either supports or disagrees with this proposed combining before the standards are drafted and posted. And some of the standards assign responsibilities to entities that should not be responsbile for some of the tasks. For example, the RC and PC are not responsible for calculating ATC. The proposed intent to combine some of the MODs as one includes the RC and PC in these standards because of the TTC calculation requirements. But in doing so, the assignment of tasks and responsibilities becomes confusing resulting in these entities being assigned some tasks inappropriately. We suggest the SDT to revise the supplementary SAR and post it for comments, with sufficient detail and specificity on the proposed scope and structure of the standard set, before drafting/revising the standards.
Response: We recognize the concern expressed by the IRC related to the SAR. However, we are attempting to both address the needs of the industry and the need to comply with the FERC Order, and felt this was the best way to meet both the requirements of the NERC process and be responsive to the Commission. Note that a SAR sets the scope of the technical content of the work, but leaves the structure of the actual standards to the Drafting Team's discretion. The Reliability Standards Development Procedure does allow the simultaneous posting of a SAR and its associated standard or standards. The drafting team refined the applicability of each standard, based on stakeholder comments and a thorough review of the latest approved version of the Functional Model, and there were several places where the applicability was revised to eliminate the Planning Coordinator and Reliability Coordinator. The drafting team has revised the standards to state more explicitly which functional entity is responsible for each requirement. Most stakeholders who commented on the SAR indicated support for the SAR as written so the drafting team did not make significant changes to the SAR. The comments on the SAR and the drafting team's responses to those comments have been publicly posted.	
ITC	As we have stated before, all compliance and measures should be based on evidence of overselling or underselling. Otherwise its just bureaucratic red-tape.
Response: The purpose the NERC standards is to maintain reliability.	
MEC	1. The purpose of each of the standards should be revised to be more in-line. The purpose in this standard be revised by replacing "to help ensure more accurage calculation of transfer capabilities" with "for reliability system

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	operations." 2. The Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and a planning horizon. Why did the Standards Drafting Team establish it and why have they defined it as provided in the standard.
Response: The standard drafting team agrees and has revised the purpose of the standard to include the phrase, 'for reliable system operations' in support of your suggestion. The standard drafting team has eliminated the term "horizons," but elected to include time periods specified by the FERC that apply to the standards.	
MRO	1. The purpose of each of the standards should be revised to be more in-line. The MRO recommends that the purpose in this standard be revised by replacing "to help ensure more accurage calculation of transfer capabilities" with "for reliability system operations." 2. The MRO notes that the Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and a planning horizon. The MRO is not familiar with the use of a scheduling horizon and questions why the Standards Drafting Team established it and why they have defined it as provided in the standard.
Response: The standard drafting team agrees and has revised the purpose of the standard to include the phrase, 'for reliable system operations' in support of your suggestion. The standard drafting team has eliminated the term "horizons," but elected to include time periods specified by the FERC that apply to the standards.	
WECC MIC MIS ATC TF	A. Reiterating comments from MOD-04 CBM, the Team suggests the following CBM definition replace the existing CBM and TRM NERC definitions: "Capacity Benefit Margin" CBM is the amount of firm import transmission capability, requested by the LSE, to exclusively serve identified load only during periods of emergency generation deficiencies extending beyond the beginning of the scheduling hour in which the emergency generation deficiency occurs." B. Typo on the first line of R1.1. Should state: "Identification of any of the following…" C. R8. Add: "Each Transmission Service Provider shall make available (within seven CALENDAR days OF A REQUEST)… (Emphasis added.) D. As previously stated, there is an existing FERC approved definition for Posted Path that should be included in the NERC Glossary and utilized in the ATC standards. R10. The term Posted Path should be used as a defined term. The definition for Posted Path should be as follows: Posted Path Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour

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	during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. E. R5. Should read "…(on each POSTED PATH or Flowgate)… F. R2. At minimum, the word "Contract Path" should be deleted as the intent is to cover all Posted Paths. This Team continues to suggest the adoption of the CFR defined term "Posted Path" that is the more accurate usage for this R. G. R11. Should be reworded as neither the Transmission Planner nor the Transmission Operator "reserve capacity" on their system(s). That's not within their Functional Model purview. The Transmission Planner and the Transmission Operator can identify capacity that "should be reserved" on their system(s); however, the Transmission Service Provider is the accurate entity to actually "reserve" the capacity.

Response:

A. The drafting team did not adopt the proposed definition of CBM as there is already an approved definition of CBM.

B. The typographical error in R1.1 was corrected.

C. The drafting team added the words, 'of a documented request' to R8 (R4 in the revised standard)

D. The drafting team adopted the proposed definition of Posted Path.

E. R5 – the word, 'Posted' was inserted in front of 'Path' as suggested

F. R2 was absorbed into R1 and the reference to 'Contract Path was eliminated as suggested.

G. R11 was deleted as suggested.