Consideration of Comments on Draft Standard — MOD-008-1 — Project 2006-07

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-008-1 – Transmission Reliability Margin Calculation Methodology. This standard was posted for a 30-day public comment period from April 16, 2008 through May 15, 2008. The stakeholders were asked to provide feedback on the standard through a special electronic Standard Comment Form. There were 33 sets of comments, including comments from 103 different people from approximately 60 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were some comments that led the drafting team to modify language to improve clarity, but none of the changes made by the drafting team changed the scope or intent of the requirements in the standard.

Applicability

- Transmission Operator or Transmission Service Provider - The April 2008 request for comments asked the industry to express their opinion on whether or not the Transmission Operator was the correct entity to be responsible for TRM. The results where 18 in favor of the TOP as the responsible entity, 5 against and 8 who had no preference. Some of the commenter's on this and other comment forms have asked for a "or" entry where the TOP or the TSP could be responsible. Current NERC standards have been written so that only one entity is (or multiple entities are) the responsible entity; so there is no question on who is accountable for a requirement. There has not yet been a standard written that established an "or" where it could be one or the other. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry. While the response to this questionnaire may not be a definitive survey of the industry preference, the team is going to go with the majority of the respondents and keep the standard as written, with the TOP responsible. For those for whom this does not result in a perfect fit with their current method of doing business, delegation of task, contract, adoption of another's work, an entity/regional/interconnection variance, or the use of a Joint Registration Entity may be appropriate means for meeting this requirement in addition to changing their current method.

- Several entities had questions and comments regarding the applicability statement in the standard and the language in some of the requirements. The team made no changes to the standard in regard to this but did paraphrase the applicability statement in some of the responses. The requirements in the standard only apply to those Transmission Operators that maintain a TRM value, and do not establish a requirement for an entity to maintain a TRM.

- Several entities have continued to express concern regarding the applicability of the ATC, TRM, and CBM standards. While the drafting team has attempted to write the standards in ways that are flexible and allow for organizational diversity, we note that FERC Order 890 makes reference to the use of Variances. Entities with non-traditional physical transmission markets or that have alternative ATC methodologies that meet or exceed the NERC ATC standards may wish to consider requesting one or more Variances related to these standards.

Requirements

- R1.1 - There were several respondents who asked questions about, made suggestions to or sought clarification on the list of uncertainties. The team modified the list slightly to further expand the list of transmission system topology differences, generation dispatch differences and to remove the timing requirement from the reserve sharing item.

- R2 - Several respondents questioned the reliability benefit of requirement 2, which limited the items that can be considered and forbids the use of elements of CBM. Requirement 2 is included in the standard as a direct response to the request of FERC in Order 890 that specified the standard should include a list of uncertainties and should restrict the utilities from straying from that list, or using any element of CBM in TRM.

Compliance

- The industry opinion regarding Violation Risk Factors for this standard as expressed in this request for comments indicates a preference 23 to 1 in favor of the current Violation Risk Factors, which are lower. The team once again iterates that it believes that per the current NERC definitions of violation risk factors, no part of this standard (TRM) if not correctly applied would have a direct affect on the state or capability of the bulk power system.

- The industry opinion regarding Violation Severity Levels for this standard as expressed in this request for comments indicates a preference 20 to 3 in favor of the current Violation Severity Levels. One commenter expressed concern on R2 having only a single VSL of severe. The drafting team believes that if a requirement is a pass/fail, and therefore has only one "VSL" that VSL has to be severe. VSL srefer to how badly a requirement was missed, not to the criticality of that particular requirement. Violation Risk Factors address the criticality of a particular element.

- Two other commenters expressed concerns on double jeopardy in the standard, or having a single event result in multiple violations. While this is an issue that has to be addressed by the compliance side of NERC and its policies, the team did review the standards with this concept in mind. As a result of this review the team revised the wording on the VSL's for Requirement 5 to reinforce that an incorrect value developed under R4, that was properly made available per R5, is not a violation of R5.

Concepts

- Several entities had questions and comments regarding the team developing a universal (mandatory) or default (recommended) TRM value. The team does not believe the have sufficient information or time in the process to gather the information, to establish a universal TRM. The transmission system varies between regions and even within regions and to arbitrarily select a TRM value or method would result in some areas suffering either an inappropriate decrease in reliability, an unnecessary decrease in market access, and more likely a mix of these problems across the entities that follow NERC standards. By the same measure the team has declined to establish a default or recommended TRM methodology or percentage, again because the team felt that lacked sufficient technical information to provide a value that was not arbitrary. The team has encouraged several respondents to pursue a white paper request or follow up SAR request to develop a dedicated team for looking at this issue.

- Several commenters questioned the removal of the tie between TRM and long term planning. The other MOD standards tie parts of the ATC development process to appropriate parts of the planning process to insure consistency and fair treatment. TRM since it applies to all users of a path will insures equal treatment to all users. All FERC Jurisdictional entities are required to have an Attachment K (planning process), this process allows market participants access to the utilities planning process, and thereby the opportunity to questions the entity on their TRM and how it is accounted for in their long term plans.

Implementation

- A popular comment related to the implementation plan. Because MOD-008 can be implemented independent of the other standards and because MOD-008 being implemented in one area and not another would not cause a coordination problem, the standard team is keeping the current implementation language.

Variance

The SDT believes it may be helpful to the industry to review the process for Variances. The Variance process can work either concurrent with or independent of the development of a standard. Because the drafting team working on a particular standard is likely to already have the necessary expertise to participate in the development of the Variance, concurrent development is generally more efficient. However, this may not always be practical; in this case, standards drafting may proceed, and even complete, prior to the development and approval of Variances. In this case, entities should seek to develop those Variances and seek their approval prior to the effective date of the standard. An entity is not exempt from meeting the requirements of the standard if the effective date has passed and that entity is in the process of developing a Variance.

The NERC process allows for three different types of variances:

- An Entity Variance
- A Regional Variance less than an Interconnection
- A Regional Variance on Interconnection-Wide basis

The NERC Rules of Procedure describe an Entity Variance as follows:

> Entity Variance — Any variance from a NERC reliability standard that is proposed to apply to one entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users, shall be approved through the regular standards development process defined in the NERC Reliability Standards Development Procedure and shall be made part of the applicable NERC reliability standard.

Entities seeking an Entity Variance should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requester is addressing the reliability goals of the standard. The ballot body is comprised of any member of the Registered Ballot Body that is interested and registers to join the ballot pool. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance Less Than an Interconnection as follows:

> Any regional variance from a NERC reliability standard that is proposed to apply for a regional entity, but not for an interconnection, shall be approved through the NERC Reliability Standards Development Procedure, except that only members of the registered ballot body located in the affected interconnection shall be permitted to vote; and the variance shall be made part of the applicable NERC reliability standard.

Entities seeking a Regional Variance Less Than an Interconnection should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requestor is addressing the reliability goals of the standard. The ballot body is comprised of any interested entities that that have registered with NERC and is a user, owner, or operator of facilities located within the interconnection in which the region requesting the Variance is located. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance on an Interconnection-wide Basis as follows:

> An interconnection-wide regional variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the NERC reliability standard. NERC shall rebuttably presume that a regional variance from a NERC reliability standard that is developed, in accordance with a procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Entities seeking a Regional Variance on an Interconnection-wide Basis should draft that Variance using the regional standards development process described in the region's delegation agreement. In that Variance, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Once approved through the regional standards development process, the Variance should be brought to NERC for filing with the appropriate regulatory authorities.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward to posting for pre-ballot review.

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 standard 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.

Index to Questions, Comments, and Responses

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.	Anita Lee (G3)	AESO		x								
2.	Ken Goldsmith (G7)	ALTW				x						
3.	Helen Stines (G1)	Alcoa Power Generating, Inc.	x		x							
4.	Eugene Warnecke (G1)	Ameren	x		x							
5.	Jason Shaver	American Transmission Company	x									
6.	Jerry Smith (G2)	APS	x									x
7.	Dave Rudolph (G7)	BEPC	x		x		x	x				
8.	Chris Bradley (G1)	Big Rivers Electric Cooperative	x		x							
9.	Denise Koehn (G6)	Bonneville Power Administration	x		x		x	x				
10.	Mike Viles (G6)	Bonneville Power Administration	x									
11.	Abbey Nulph (G6)	Bonneville Power Administration	x									
12.	Don Watkins (G6)	Bonneville Power Administration	x									
13.	Patrick Roechelle (G6)	Bonneville Power Administration	x									
14.	Kammy Rogers-Holiday (G6)	Bonneville Power Administration	x									
15.	Robin Chung (G6)	Bonneville Power Administration			x		x	x				
16.	Rebecca Berdahl (G6)	Bonneville Power Administration			x							
17.	Susan Millar (G6)	Bonneville Power Administration	x									
18.	Todd Miller (G6)	Bonneville Power Administration			x		x	x				
19.	Elizabeth Loebach (G6)	Bonneville Power Administration	x									
20.	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	x				x					
21.	Dave Lunceford (G2)	California ISO		x								x

22.	Brent Kingsford (G3)	California ISO		x								
23.	Paul Bleuss (G5)	California ISO		x								
24.	Frank Cumpton	California ISO		x								
25.	Paul Rocha	CenterPoint Energy	x									
26.	Greg Rowland	Duke Energy Corporation	x		x		x	x				
27.	Reza Ebrahimian	Electric Service Delivery	x									
28.	Jim Case (G5)	Entergy Services, Inc.	x									
29.	Narinder K. Saini (G8)	Entergy Services, Inc.	x									
30.	Joachim Francois (G1) (G8)	Entergy Services, Inc.	x		x							
31.	Ed Davis (G8)	Entergy Services, Inc	x									
32.	George Bartlett (G8)	Entergy Services, Inc	x									
33.	Lynna Estep (G8)	Entergy Services, Inc	x									
34.	Michelle Bourg (G8)	Entergy Services, Inc	x									
35.	Matt McNeece (G8)	Entergy Services, Inc	x									
36.	Cameron Warren (G8)	Entergy Services, Inc	x									
37.	Joachim Francois (G8)	Entergy Services, Inc	x									
38.	Joachim Francois (G1)	Entergy Services, Inc.	x		x							
39.	Jack Cashin/Barry Green	EPSA					x	x				
40.	H. Steven Myers (I) (G3) (G5)	ERCOT ISO		x								
41.	Eric Mortenson	Exelon	x		x							
42.	Doug Hohlbaugh	FirstEnergy	x		x		x					
43.	Dave Folk	FirstEnergy	x		x		x					
44.	Rob Martinko	FirstEnergy	x		x		x					
45.	Sam Ciccone	FirstEnergy	x		x		x					
46.	Ralph Anderson (G5)	FMPA				x						
47.	Earl Fair	Gainesville Regional Utilities	x		x		x					
48.	Ross Kovacs (G1)	Georgia Transmission Corp.	x									
49.	Joseph Knight (G7)	GRE	x		x		x	x				
50.	David Kiguel (G4)	Hydro One Networks	x		x							
51.	Alessia Dawes	Hydro One Networks	x		x							
52.	Roger Champagne (G4)	Hydro Quebec TransEnergie	x	x								
53.	Ron Falsetti (G3) (I)	IESO		x								
54.	Matt Goldberg (G3)	ISO-New England		x								
55.	Kathleen	ISO-New England		x								

	Goodman (G4)											
56.	Jim Useldinger	Kansas City Power & Light	x									
57.	Eric Ruskamp (G7)	LES	x		x		x	x				
58.	Maria Neufeld	Manitoba Hydro	x		x		x	x				
59.	Joe DePoorter (G7)	MGE			x	x	x	x				
60.	John Harmon	MISO		x								
61.	Bill Phillips (G3)	MISO		x								
62.	Jason Marshall (G5)	MISO		x								
63.	Terry Bilke (G7)	MISO		x								
64.	Carol Gerou (G7)	MP	x		x		x	x				
65.	Larry Brusseau (G7)	MRO										x
66.	Mike Brytowski (G7)	MRO										x
67.	Tom Mielnik (G7)	MRO NERC Standards Review Subcommittee	x		x		x	x				
68.	Jerry Tang (G1)	Municipal Electric Auth. of GA	x		x							
69.	Rick Gonzales	New York Independent System Operator		x								
70.	Greg Campoli (G4)	New York ISO		x								
71.	Ralph Rufrano (G4)	New York Power Authority	x			x	x	x			x	
72.	Rick White (G4)	Northeast Utilities	x			x						
73.	Guy V. Zito (G4)	NPCC										x
74.	Alan Adamson (G4)	NYSRC										
75.	Jim Castle (G3)	NYISO		x								
76.	Greg Ward / Darryl Curtis	Oncor Electric Delivery	x									
77.	Aaron Staley	Orlando Utilities Commission	x		x		x				x	
78.	Richard Kafka	Pepco Holdings, Inc.	x		x		x	x				
79.	Patrick Brown (G3) (I)	PJM		x								
80.	John Cummings (G4)	PPL EnergyPlus						x				
81.	Jon Williamson (G4)	PPL EnergyPlus						x				
82.	Mark Hemibach (G4)	PPL Generation/PPL EnergyPlus					x	x				
83.	Annette Bannon	PPL Supply Group	x		x		x	x				
84.	Phil Creech (G1)	Progress Energy - Carolinas	x		x							
85.	Phil Riley	Public Service Commission of South Carolina									x	
86.	W. Shannon Black (G2)	Sacramento Municipal Utility District			x							
87.	Pat Huntley (G1)	SERC										x
88.	John Troha (G1)	SERC										x

89.	Doug Bailey (G1)	SERC Available Transfer Capability Working Group (ATCWG)	x		x						x	
90.	Vicky Budreau (G1)	So. Carolina Public Service Auth.	x		x							
91.	Al McMeekin (G1)	South Carolina Electric & Gas	x		x							
92.	Stan Shealy (G1)	South Carolina Electric & Gas	x		x							
93.	Jim Griffith (G1)	Southern Co.	x		x							
94.	DuShaune Carter (G1)	Southern Co.	x		x							
95.	Kevin Bates	Southwest Power Pool		x								
96.	Charles Young (G3)	Southwest Power Pool		x								
97.	Chuck Falls (G2)	SRP	x									x
98.	Rex McDaniel	Texas-New Mexico Power Company	x									
99.	Brian Evans Mongeon G4)	Utility Services, LLC						x				
100.	Ji Haigh	WAPA	x					x				
101.	Neal Balu (G7)	WPS			x	x	x	x				
102.	Pam Oreschnick (G7)	Xcel Energy	x		x		x	x				
103.	Alice Druffel	Xcel Energy	x		x		x	x				

I — Individual
G1 — SERC Available Transfer Capability Working Group
G2 — WECC Market Interface Committee / Sub Commtt / ATC Task Force
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G5 — NERC RTO SDT
G6 — BPA
G7 — MRO Standards Review Committee
G8 — Entergy Services

1. Some entities have indicated they believe the Transmission Operator should not be an applicable entity in the TRM standard (MOD-008). The Drafting Team believes that the Transmission Operator is the appropriate entity since the Transmission Operator is ultimately responsible for operating a reliable system while using all Transmission Service Providers' calculated available capability. The drafting team also believes that the Transmission Operator can, via mutual agreement, delegate these tasks to other entities (such as Transmission Service Providers, ISOs, or RTOs). Do you believe the Transmission Operator is the correct responsible entity for the tasks it has been assigned in MOD-008? If "No," please identify requirements where the Transmission Operator is incorrect and specify who the correct entity should be.

Summary Consideration:

The April 2008 request for comments asked the industry to express its opinion on this issue. The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Some of the commenters on this and other comment forms have asked for an "or" entry where the TOP or the TSP could be responsible. Current NERC standards have been written so that only one entity is (or multiple entities are) the responsible entity; so there is no question on who is accountable for a requirement. There has not yet been a standard written that established an "or" where it could be one or the other. Given that restriction, the requirement has to be written for only one entity.

It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry. While the response to this questionnaire may not be a definitive survey of the industry preference, the team is going to go with the majority of the respondents and keep the standard as written, with the TOP responsible. For those for whom this does not result in a perfect fit with their current method of doing business, delegation of task, contract, adoption of another's work, an entity/regional/interconnection variance, or the use of a Joint Registration Entity may be appropriate means for meeting this requirement in addition to changing their current method.

Organization/Group	Question 1:	Question 1 Comments:
Xcel Energy	No	We feel that the applicability should apply to the TSP, recognizing that the TSP will require input from the TOP. To further explain, the ATC/AFC methodology is primarily a mechanism for the TSP to sell/provide transmission service in a manner that ensures the transmission system is secure .A TOP however will utilize SOLs and IROLs in the operations of the transmission system, and do not necessarily have to be the same as the ATC/AFC components. As an example, in the selling of service, TRM will not be sold so the limit =TTC-TRM. However the TOP may operate into the TRM during real-time operations and not hold this margin, but honor the true system limit. As another example, there are interdependent flowgates where the ATC components will be based on the most conservative combination, but the system will be operated to minimize restrictions. This may result in a sliding operating limit for the TOP based on actual conditions, while a TSP has to use the most conservative limits for ATC/AFC.
Response: The April 2008 request for comments asked the industry to express their opinion on this issue The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is		

<table>
<tr><th>Organization/Group</th><th>Question 1:</th><th>Question 1 Comments:</th></tr>
<tr><td colspan="3">no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. TRM applies only to the calculation of ATC, and is not an operational requirement on the TOP that would restrict its actions.</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>The Transmission Service Provider should also be listed as an appropriate entity along with the TOP in all requirements, so that either entity could perform this function.</td></tr>
<tr><td colspan="3">Response: The April 2008 request for comments asked the industry to express their opinion on this issue The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.</td></tr>
<tr><td>FirstEnergy</td><td>No</td><td>Within many RTO areas it is the TSP who maintains the TRM Methodology and assures its appropriate implementation while calculating ATC or AFC. This is the case in a large portion of the continent and a standard should not be written in a way that would knowingly require an assignment delegation for a large number of potential responsible entities. Assigning the applicability in this standard to the TSP would work for non-market areas of the continent since in those areas the TOP most likely serves as its own TSP.</td></tr>
<tr><td colspan="3">Response: The April 2008 request for comments asked the industry to express their opinion on this issue The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.</td></tr>
<tr><td>AEP</td><td>No</td><td>The Transmission Service Provider is the applicable entity.</td></tr>
<tr><td colspan="3">Response: The April 2008 request for comments asked the industry to express their opinion on this issue. The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.</td></tr>
<tr><td>Gainesville Regional Utilities</td><td>No</td><td>I would suggest the TSP and let that entity negotiate, via mutual agreement, to delegate these task.</td></tr>
</table>

Organization/Group	Question 1:	Question 1 Comments:
Response: The April 2008 request for comments asked the industry to express their opinion on this issue. The results where 18 in favor of the TOP as the responsible entity, 5 against and 8 who had no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.		
American Transmission Company	Yes	We agree that the Transmission Operator is the correct entity but are concerned with the inserted exclusion. Why did the SDT insert the exclusion in this draft of the Standard? (No previous drafts contained this exclusion.)How would a TOP go about notifying NERC that MOD-008 is not applicable to them? How would NERC or the Regions know if something changed and the TOP is now performing TRM? When would this standard apply to a TOP that does not currently perform a TRM? An alternate approach is to have TOPs that do not perform TRMs, Certify yearly that they do not perform TRMs and therefore satisfy MOD-008-1.
Response: The April 2008 request for comments asked the industry to express their opinion on this issue. The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.		
Brazos Electric Power Cooperative, Inc.	Yes	The TOP is the responsible entity however, if the TOP operates in a single-control area region the establishment and applicability of TRM may have no reliability benefits.
Response: Thank you for your supportive comment.		
WECC Market Interface Committee ATC Task Force	Yes	
Exelon	Yes	
NPCC Regional Standards Committee	Yes	
WECC Market Interface Committee / Sub Commtt / ATC	Yes	

Organization/Group	Question 1:	Question 1 Comments:
Task Force		
PJM	Yes	
Duke Energy Corporation	Yes	
Bonneville Power	Yes	
Pepco Holdings, Inc	Yes	
ISO RTO Council/Standards Review Committee (SRC)	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Ontario IESO	Yes	
Hydro One Networks	Yes	
Entergy Services Inc.	Yes	
The Midwest ISO	Yes	
Southwest Power Pool	Yes	
New York Independent System Operator	Yes	
Public Service Commission of South Carolina	No preference	
Orlando Utilities Commission	No preference	
Oncor Electric	No	

Organization/Group	Question 1:	Question 1 Comments:
Delivery	preference	
Texas-New Mexico Power company	No preference	
Manitoba Hydro	No preference	
SERC ATCWG	No preference	
EPSA	No preference	
ERCOT ISO	No preference	

2. The drafting team modified some requirements and associated measures to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct. Incorrect Requirement(s) or Measure(s):

Summary Consideration:

Several entities had questions on requirements applying to TOP's or TSP's. A summary of the team's resolution is presented in the "summary consideration" for question #1.

Several entities had questions and comments regarding the applicability statement in the standard and the language in some of the requirements. The team made no changes to the standard in regard to this, but did paraphrase the applicability statement in some of the responses. The requirements in the standard only apply to those TOP's who maintain a TRM value, and do not establish a requirement for an entity to maintain a TRM.

Several entities had questions and comments regarding the team developing a universal (mandatory) or default (recommended) TRM value. The team does not believe it has sufficient information or time in the process to gather the information, to establish a universal TRM. The transmission system varies between regions and even within regions; to arbitrarily select a TRM value or method would result in some areas suffering either an inappropriate decrease in reliability, an unnecessary decrease in market access, and more likely a mix of these problems across the entities that follow NERC standards. By the same measure, the team has declined to establish a default or recommended TRM methodology or percentage, again because the team felt that it lacked sufficient technical information to provide a value that was not arbitrary. The team has encouraged several respondents to pursue a white paper request or follow up SAR request to develop a dedicated team to look at this issue.

Several commenters questioned the removal of the tie between TRM and long term planning. The other MOD standards tie parts of the ATC development process to appropriate parts of the planning process to insure consistency and fair treatment. TRM, since it applies to all users of a path, will insure equal treatment to all users. All FERC Jurisdictional entities are required to have an Attachment K (planning process). This process allows market participants access to the utilities' planning processes, and thereby the opportunity to question an entity on its TRM and how it is accounted for TRM in its long term plans.

Several respondents questioned the reliability benefit of requirement 2, which limits the items that can be considered and forbids the use of elements of CBM. Requirement 2 is included in the standard as a response to the directive in FERC Order 890 that specified the standard should include a list of uncertainties and should restrict the utilities from straying from that list, or using any element of CBM in TRM.

There were several respondents who asked questions about, made suggestions to, or sought clarification on the list of uncertainties. The team modified the list slightly to further expand the list of transmission system topology differences, generation dispatch differences and to remove the timing requirement from the reserve sharing item.

Organization/Group	Question 2 - Incorrect Requirement(s) or Measure(s):
EPSA	We believe that the former requirement R1.2 which established the consistency between planning assumptions and those used in calculation TRM was appropriate and do not agree with its deletion. **Response:** The TRM standards should apply only to the calculation of TRM and its application for the determination of ATC. The team removed the consistency clause in response to comments and supports this with three reasons. The first being that any requirement linking TRM methodology with planning assumptions would need to be in the planning standard, to do otherwise is to create the potential for conflicting standards where meeting both is not possible. Second, the entity's open planning process (as documented in its OATT Attachment K) provides opportunity to address any unfairness between the TRM and its planning process. Finally, TRM is intended to be based on conditions other than those expected, so requiring assumptions to be consistent with those used in planning of operations would be contrary to the goal of TRM. In R3, the previous draft of the standard required sharing of "underlying documentation, work papers and load flow base cases". In the current draft, the latter two of the listed items have been deleted. It is acceptable to us if this is done merely because they are deemed to be redundant as they are included within the meaning of "underlying documentation". If this was not the intent of the drafters, we would disagree with this change as those are items that would be required in order to reproduce the studies that have led to the posted ATC values. **Response:** The intent of the requirement is that "underlying documentation" would include work papers, load flow cases and any other reference material used to create the TRM.
Response: Please see in-line responses.	
WECC Market Interface Committee / Sub Commtt / ATC Task Force	The Team suggests moving the final phrase of the proposed R3 Requirement to the beginning of the sentence to add clarity. (This is a non-substantive change.) The new R would read: No more than 30 calendar days after receiving a request, each Transmission Operator shall make available its TRMID, and if requested, its underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request for that data:
Response: The SDT has tried to use a consistent structure for the requirements, and believes the suggested change would not add sufficient clarity to warrant the change at this time.	
Kansas City Power & Light	Add "or Transmission Service Provider" after Transmission Operator in all requirements.

Organization/Group	Question 2 - Incorrect Requirement(s) or Measure(s):
Response: The April 2008 request for comments asked the industry to express their opinion on this issue. The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.	
WECC Market Interface Committee ATC Task Force	The Team suggests moving the final phrase of the proposed R3 Requirement to the beginning of the sentence to add clarity. (This is a non-substantive change.)The new R would read :No more than 30 calendar days after receiving a request, each Transmission Operator shall make available its TRMID, and if requested, its underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request for that data:
Response: The SDT has tried to use a consistent structure for the requirements, and believes the suggested change would not add sufficient clarity to warrant the change at this time.	
ERCOT ISO	Requirement 1:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: " Requirement 2:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. " Requirement 3: I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request."
Response: Because the applicability already exempts any entities that do not maintain TRM from the standard, these changes will not be adopted.	
Exelon	In MOD-008-1 the following requirement was removed: R1.2.A A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in the Transmission planning process for the time period studied". The NERC ATCWG reached conclusion on the following rule as they were developing the "Transmission Capability Margins and Their Use in ATC Determination" white paper which discusses the reliability margins of TRM and CBM: A Transmission Provider's ATC/AFC calculations, and associated margins, must be consistent with the Transmission Owners and Public Power Entities documented

Organization/Group	**Question 2 - Incorrect Requirement(s) or Measure(s):**
	Planning Criteria. This rule was incorporated into the "Transmission Capability Margins and Their Use in ATC Determination? white paper dated June 17, 1999 as demonstrated in the following exert:? ?The methodology used to derive TRM and its components must be documented and consistent with published planning criteria, and must not account for uncertainties already accounted for elsewhere in the ATC determination. A TRM is considered consistent with published planning criteria if the same components that comprise it are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process? AFC/ATC calculations must be consistent with each Transmission Owner's planning criteria in order to maintain reliability. AFC/ATC calculations must not be subject to evaluation scenarios that exceed or are "beyond" the applicable planning criteria. For example, if the most extreme event a Transmission Owner plans for were single contingencies, it would be inconsistent with the applicable planning criteria to evaluate a transmission service request to meet a double contingency test. In this instance, evaluating a transmission service request using double contingency analysis would be in conflict with the planning criteria and would not be compatible with the reliability requirements used to serve native connected load. In an ATC calculation the following components determine the loading on a flowgate for the period of time under evaluation: 1. Base Case Flows (which recognizes the forecasted load connected to the transmission network and planned system topology) 2. Impacts of existing transmission service reservations -- both positive and negative (i.e. counterflow) 3. TRM (consistent with applicable Planning Criteria) 4. CBM (consistent with applicable Planning Criteria) When these four components are applied to a flowgate the result is a calculated AFC. If the resultant AFC is negative, the result indicates that the flowgate is projected to be overloaded because of the preexisting commitments (i.e. the four components listed above). In some cases negative AFC values exist for future years preventing transmission customers from obtaining transmission reservations for these future time periods. The inconsistency between Transmission Provider's AFC/ATC calculations and the Transmission Owner's Planning criteria becomes evident when the Transmission Owner internal planning processes does not result in identification of system deficiencies requiring system expansion — even on Flowgate determined by the Transmission Provider to have negative AFC values far into the future. The likely cause of this discrepancy is that the TO is not applying the same scenario, including the same transmission uses (i.e. confirmed reservations), or consistent margins (TRM/CBM) in its internal planning process.
Response: The relationship between an entity's TTC/TFC/AFC/ATC/CBM and other calculations and the operations and transmission planning process are discussed in the responses to the comments submitted on those other applicable MOD standards. The TRM standard was written to	

Organization/Group	Question 2 - Incorrect Requirement(s) or Measure(s):
only apply to the calculation of TRM and its application for the determination of ATC. The team removed the consistency clause in response to comments and supports this with three reasons. The first being that any requirement linking TRM methodology with planning assumptions would need to be in the planning standard, to do otherwise is to create the potential for conflicting standards where meeting both is not possible. Second, the entity's open planning process (as documented in its OATT Attachment K) provides opportunity to address any unfairness between the TRM and its planning process. Finally, TRM is intended to be based on conditions other than those expected, so requiring assumptions to be consistent with those used in planning of operations would be contrary to the goal of TRM.	
FirstEnergy	R2 – This requirement states "Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM." We recommend replacing "only use" with "include" since "only use" presumes that the list of uncertainties stated in the standard are all inclusive of all factors that a TOP/TSP may want to address in TRM. The requirement explicitly states that CBM should not be included in TRM, so making this change should not create an opportunity for double dipping on CBM.
Response: Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The Order also requested that the standard specify that TRM not include elements of CBM.	
PJM	Although the SDT had the appropriate Team to establish a default percentage for TRM, the FERC deadline did not allow enough time to complete this portion of the requirement. Since TRM is a reliability margin, PJM encourages the Team to provide what ever input it currently has in a ?parking lot? for a possible future Team to undertake the development activity. There should be a default percentage to be used without requiring specific documentation, work papers and load flow cases if a straight percentage such as 5% is used. Additional information would be required only if a greater percentage is used.
Response: The drafting team, in numerous discussions, examined the use of a fixed percentage rather then specifying the areas of uncertainty. The standard as it is currently written does not require or forbid the use of a fixed percentage as a margin, but does require that the entity explain the rationale for the percentage. Additionally the standard requires that the margin represent only the areas of uncertainty specified in R1 and not include any items included in CBM. We encourage PJM to draft a SAR if further development in TRM is desired and/or file for a variance that more clearly permits a flat percentage.	
Pepco Holdings, Inc	PHI supports the comments of PJM and will not submit duplicate comments
Response: Please see PJM response.	
Oncor Electric Delivery	All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would

Organization/Group	Question 2 - Incorrect Requirement(s) or Measure(s):
	add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s).
Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt form this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	
Gainesville Regional Utilities	R2: Why limit what items can be considered in developing TRM? What reliability purpose could it possibly serve? R1,3,4 & 5 are OK as presented.
Response: Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The Order also directed that the standard specify that TRM not include elements of CBM.	
MRO NERC Standards Review Subcommittee	1. The MRO believes that M1 should be revised to delete the words "all" from the phrase "all specified information?" This use of "all" seem to be unnecessary and may result in over-the-top auditing. **Response:** The SDT intends for the measure to determine if all sub-requirements were addressed, not if all bullets in R1.1 were included. Each bullet in R1.1 is only required if used, as described in the sub-requirement. 2. The MRO commends the SDT on deleting R1.2.A and R1.5. The MRO believes that these former requirements were unnecessary and not reliability related and that the changes are significant improvements to the standard. **Response:** Thank you for your supportive comment. 3. The MRO is asking for clarification in R1.1 on "Reserve sharing requirements". The MRO is assuming that this is not non-operating reserves such as planning reserves. **Response:** MRO is correct; this is not intended to cover planning reserves. This was not meant to be specific to a particular arrangement, but to cover any generation reserve sharing agreement that might require a margin on the

Organization/Group	Question 2 - Incorrect Requirement(s) or Measure(s):
	transmission system for delivery. 4. R1.1, bullet 7 reads: Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window). The "59-minute window" conflicts with BAL-002. Under BAL-002, operating reserves can be supplied for up to 105 minutes (R4.2 15 minutes for the disturbance plus R6.2 90 minutes). We suggest the following wording instead: "(Operating Reserve actions not exceeding the operating reserve sharing deployment period)". **Response:** The SDT will not comment on whether or not the statement regarding provision of reserves for up to 105 minutes is correct or incorrect. The team eliminated the 59-minute limitation since this was not meant to identify a specific arrangement but a category of arrangements.
3. **Response:** Please see in-line responses.	
Entergy Services Inc.	R2 – Entergy recommends deleting the phrase "and shall not include any of the components of Capacity Benefit Margin (CBM).
Response: Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The order also directed that the standard specify that TRM not include elements of CBM.	
The Midwest ISO	R1.1 – Please clarify the uncertainty components below: o Allowances for simultaneous path interactions (how is it different from loop flow above?) **Response:** Different parts of the country refer to these concepts using a variety of terms with a variety of definitions ranging from overlapping definitions to distinct and exclusive definitions. Listing of both allows for greater flexibility since neither is a defined term. Short-term System Operator response (Does this exclude reserve sharing requirements?). **Response:** "Reserve sharing requirements" is listed as the next sub bullet under "System Operator Response", so it doesn't matter if short term system operator response includes reserve sharing requirement – provided the values are not duplicated. R2 — This requirement as it is written doesn't allow the Transmission Operators to include any other uncertainties other than from R1.1. If R1.1 is not trying to list the complete set of uncertainties, we recommend to revise R2 to "Each Transmission Operator shall not include any of the components of Capacity Benefit Margin (CBM)" **Response:** Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The order

Organization/Group	**Question 2 - Incorrect Requirement(s) or Measure(s):**
	also directed that the standard specify that TRM not include elements of CBM.
Response: Please see in-line responses.	
American Transmission Company	Modification Requirement 1: Each TOP shall prepare and keep current a Transmission Reliability Margin Implementation Document (TRMID) that includes the following information: The phrase "as a minimum" is not needed because the TOP has to include all sub-requirement in order to meet requirement 1. Any information above that which is listed is outside of NERC's audit **Response:** While the requirement specifies that you can only use the listed items to determine TRM, entities may provide additional information beyond that which is required in the TRMID (e.g., examples of calculations). Using the phrase "as a minimum" insures an entity can include the additional information without a compliance issue. Modifications to Requirement 4: Each TOP shall establish TRM values in accordance with the TRMID at least once every 13 months. Modification to Requirement 5: The TOP shall provide the TRM values to its TSP(s) and TP(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. The phrase "using TRM" conflicts with Requirements 1 - 3. In addition we believe the deletion aligns with our comment on the applicability section. **Response:** We have included this in R4 and R5 to further emphasize that TOPs without TRM don't need to do this, even though it is redundant with the applicability section. M1 should be revised to delete the words "all" from the phrase "all specified information?" to avoid being overly inclusive. **Response:** The SDT intends for the measure to determine if all sub-requirements were addressed, not if all bullets in R1.1 were included. Each bullet in R1.1 is only required if used, as described in the sub-requirement.
Response: Please see in-line responses.	
Xcel Energy	R1.1, bullet 7 reads: Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window). The "59-minute window" seems arbitrary and potentially conflicting. We suggest the following wording instead: "(Operating Reserve actions not exceeding the reserve sharing deployment period)". If the drafting team does not like the suggestion, then please clarify what is the basis for an odd # of minutes, instead of using more common 1/4 or full hour increments? Under BAL-002, operating reserves can be supplied for up to 105 minutes (15 minutes for the disturbance plus 90 minutes).
Response: The SDT will not comment on whether or not the statement regarding provision of reserves for up to 105 minutes is correct or incorrect.	

Organization/Group	Question 2 - Incorrect Requirement(s) or Measure(s):
The team eliminated the 59-minute limitation since this was not meant to identify a specific arrangement but a category of arrangements.	
Texas-New Mexico Power company	All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s).
Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose maintain TRM, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	
PPL Supply Group	R3. PPL suggests that the Purchasing/Selling Entities should be included in the listing of entities under Requirement R3.
Response: Purchasing and Selling entities in the opinion of the team do not have a transmission reliability need to access those items. This is an openness and transparency issue that would best be addressed in an entity's OATT or in business practices.	
New York Independent System Operator	The NYISO has previously commented that R4 would require TRM to be recalculated more frequently than necessary for Transmission Operators whose TRM assumptions do not change frequently. Under the NYISO system, TRM values are stable over time and often do not change for periods longer than 13 months. The NYISO therefore renews its request that the SDT modify R4 to specify that TRM need not be re-established (or re-calculated) every 13 months to the extent that none of the underlying TRM inputs have changed. The SDT has previously revised R8 under MOD-001 in the same manner and there is every reason to make the same change to R4 under MOD-008.
Response: The current wording of R4 was in part in response to NYISO's earlier comment and the SDT believed they had addressed it. The phrase "establish" was chosen to allow entities to simply republish prior values each year if their inputs have not changed. Changing to your suggested language would require an entity to "prove" their inputs haven't changed.	

Organization/Group	Question 2 - Incorrect Requirement(s) or Measure(s):
Bonneville Power	BPA does not believe any are incorrect.
Response: Thank you for your supportive comment.	
Ontario IESO	None
Hydro One Networks	None
NPCC Regional Standards Committee	None

4. The drafting team has modified the Violation Risk Factors for MOD-008 to reflect industry concerns that they did not reflect NERC's VRF definitions. NERC's VRF definitions are listed below. Are the current VRFs established correctly? If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.

High Risk Requirement:

(a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement:

(a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement: is administrative in nature and

(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or

(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

Summary Consideration:

The industry opinion as expressed in this request for comments indicates a preference in favor of the current Violation Risk Factors, which are lower. The team once again iterates that it believes that per the current NERC definitions of violation risk factors, no part of this standard (TRM) if not correctly applied would have a direct affect on the state or capability of the bulk power system.

Organization/Group	Question 3:	Question 3 Comments:
Ontario IESO	No	The VRF for R4 should be a Medium. R4 stipulates that the TOP establish a TRM. Given that TRM is

Organization/Group	Question 3:	Question 3 Comments:
		that portion of the ATC reserved to cover for uncertainties that can affect transmission reliability, failure to establish this value could result in the TOP facing unreliable operations due to the TSP offering and committing this value as a transmission service to transmission users. The end result could have a direct impact on the control and reliability of the BES.
Response: The drafting team disagrees. The majority of the team and industry believes that a violation of R4 does not directly affect the electrical state or the capability of the bulk power system.		
FirstEnergy	Yes	FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating. We concur with the team's reasoning and rationale provided in response to ballot comments in making this change.
Response: Thank you for your supportive comment.		
PJM	Yes	PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of "Lower." A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system.
Response: Thank you for your supportive comment.		
ISO RTO Council/Standards Review Committee (SRC)	Yes	The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.
Response: Thank you for your supportive comment.		
MRO NERC Standards Review Subcommittee	Yes	The MRO commends the SDT on revising the VRFs to Lower. We believe the revised VRFs are in-line with the NERC definitions of the VRF levels.
Response: Thank you for your supportive comment.		
SERC ATCWG	Yes	
WECC Market Interface Committee /	Yes	

Organization/Group	Question 3:	Question 3 Comments:
Sub Commtt / ATC Task Force		
Kansas City Power & Light	Yes	
WECC Market Interface Committee ATC Task Force	Yes	
Manitoba Hydro	Yes	
Public Service Commission of South Carolina	Yes	
Duke Energy Corporation	Yes	
Bonneville Power	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc		
Gainesville Regional Utilities	Yes	
Hydro One Networks	Yes	
Entergy Services Inc.	Yes	
The Midwest ISO	Yes	
Southwest Power Pool	Yes	
American Transmission Company	Yes	
Xcel Energy	Yes	
Texas-New Mexico Power company	Yes	
Orlando Utilities	Yes	

Organization/Group	Question 3:	Question 3 Comments:
Commission		
New York Independent System Operator	Yes	
EPSA		no comment

5. The drafting team has modified the Violation Severity Levels for MOD-008 to reflect industry concerns that they were too “pass/fail” oriented. Are the current VSLs established correctly? If “No,” please identify specific VSLs and suggest changes to the language.

Summary Consideration:

The industry opinion as expressed in this request for comments indicates a preference in favor of the current Violation Severity Levels. One commenter expressed concern on R2 having only a single VSL of severe. The drafting team believes that if a requirement is a pass/fail, and therefore has only one “VSL” that VSL has to be severe. VSLs refer to how badly a requirement was missed, not to the criticality of that particular requirement. Violation Risk Factors address the criticality of a particular element.

Two other commenters expressed concerns on double jeopardy in the standard, or having a single event result in multiple violations. While this is an issue that has to be addressed by the compliance side of NERC and its policies, the team did review the standards with this concept in mind. As a result of this review the team revised the wording on the VSL’s for Requirement 5 to reinforce that an incorrect value developed under R4, that was properly made available per R5, is not a violation of R5.

Organization/Group	Question 4:	Question 4 Comments:
PJM	No	NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations — this language to be added to the standard.
Response: The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events. VSLs for R2: SDT modified the phrasing to be clear so that if you use CBM (in violation of R2) you aren’t double penalized for also violating the “only the components of…” VSLs for R5: The SDT modified all four VSLs to be clear that the accuracy portion refers to the values matching those developed in R4, not the absolute accuracy of the values. This was to make the VSL clearly match the requirement in R5 for transmission of values. This is for a situation where the values are incorrect, but were transmitted. The violation would be of R4, not of R5.		
FirstEnergy	No	The Severe VSL stated for requirement R2 does not seem appropriate if a TOP/TSP included elements of uncertainty that were outside of those items explicitly stated in R1 so long as all of the items in R1 are covered AND that CBM is not included in its TRM. See proposed change above for R2.
Response: Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements		

Organization/Group	Question 4:	Question 4 Comments:
that do not allow the use of uncertainty other then those in the list. The order also directed that the standard specify that TRM not include elements of CBM. The Violation Risk Factor determines the impact a violation could have on the bulk electric system, the Violation Severity Level is a measure of how badly a requirement was violated. In the case of a pass/fail requirement, the violation severity level is severe.		
ISO RTO Council/Standards Review Committee (SRC)	No	NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that the potential for double counting of violations for a single event be eliminated.
Response: The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events. VSLs for R2: SDT modified the phrasing to be clear so that if you use CBM (in violation of R2) you aren't double penalized for also violating the "only the components of…" VSLs for R5: The SDT modified all four of the VSLs to be clear that the accuracy portion refers to the values matching those developed in R4, not the absolute accuracy of the values. This was to make the VSLs clearly match the requirement in R5 for transmission of values. This is for a situation where the values are incorrect, but were transmitted. The violation would be of R4, not of R5.		
SERC ATCWG	Yes	
WECC Market Interface Committee / Sub Commtt / ATC Task Force	Yes	
Kansas City Power & Light	Yes	
WECC Market Interface Committee ATC Task Force	Yes	
Manitoba Hydro	Yes	
NPCC Regional Standards Committee	Yes	
Public Service	Yes	

Organization/Group	Question 4:	Question 4 Comments:
Commission of South Carolina		
Duke Energy Corporation	Yes	
Bonneville Power	Yes	
Oncor Electric Delivery	Yes	
Gainesville Regional Utilities	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Ontario IESO	Yes	
Hydro One Networks	Yes	
Entergy Services Inc.	Yes	
The Midwest ISO	Yes	
American Transmission Company	Yes	
Xcel Energy	Yes	
Texas-New Mexico Power company	Yes	
Orlando Utilities Commission	Yes	
EPSA		no comment

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

Summary Consideration:

A popular comment under question 5 related to the implementation plan. Because Mod 008 can be implemented independent of the other standards and because Mod 008 being implemented in one area and not another would not cause a coordination problem, the standard team is keeping the current implementation language.

EPSA made some very detailed comments, and the team attempted to respond to all of them. Those responses to EPSA's comments are below in the individual comments.

Many of the other comments and questions posted under question #5 are similar or verbatim repetitions of questions asked under questions 1-4, so their summary will not be repeated here.

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

Organization/Group	Question 5 Comments:
CenterPoint Energy	The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area.
Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	
EPSA	This comment relates also to the NAESB recommendation that no additional business practices related to TRM will be

Organization/Group	Question 5 Comments:
	developed. Our comments are based also on Order 890 Paragraph 207 which states in part: "The purpose of increasing the consistency and transparency of ATC calculations is to reduce the potential for undue discrimination in the provision of transmission service, specifically by reducing the opportunity for transmission providers to exercise excessive discretion. We find that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. In order to minimize this discretion, the Final Rule requires that all ATC components (i.e., TTC, ETC, CBM, and TRM) and certain data inputs, data exchange, and assumptions be consistent and that the number of industry-wide ATC calculation formulas be few in number, transparent and produce equivalent results ."EPSA does not believe that the mandate given by FERC to NERC and to NAESB has been carried out. EPSA accepts that in calculating ATC, Transmission operators need a margin, which is deducted from the TTC or AFC as appropriate, to allow for uncertainties in forecast conditions and thus to insure that Transmission Service is not oversold. As it represents an allowance for uncertainties, it is recognized that TRM is based on assumptions about future conditions and is in general, determined probabilistically. However, based on the proposed actions of the two standards development organizations, in order to meet FERC's Order to "increas[e] the consistency and transparency of ATC calculations" and to "reduc[e] the opportunity for transmission providers to exercise excessive discretion" the industry has provided standards that: ? Require Transmission Operators to only identify various elements if they are used in establishing TRM. At no point in the standard however, is any direction provided on how the Transmission Operators determine whether or not to use the various components or, if used, how values are to be established. ? Make no provision for monitoring or reporting on utilization of TRM? Make no provision for verifying from season to season or year to year whether the values utilized in establishing TRM were or remain appropriate. These standards therefore impose only a minimal requirement for transparency and no requirement for consistency in establishing TRM and no requirement to monitor its usage to verify that assumed values are appropriate. The current NERC and NAESB standards on TRM are reminiscent of the previous NERC standard on ATC which was developed in response to Order 888. It required only that Transmission Operators document their methodology for calculating ATC, much like other fill-in-the-blank standards. Clearly in approving Order 890 and more particularly in Order 693 where they declined to approve other industry fill-in-the-blank standards, FERC has determined that such a standard is insufficient. Yet, with respect to TRM, the industry, through NERC and NAESB, seems prepared to submit standards to FERC that demonstrate that very little progress has been made.

Response: There was a lot of ground covered in this comment, and it is not really possible to break it into sections like some of the other commenter's submittals. The team will attempt to answer the various topics by addressing them individually.

Tracking TRM: Unlike CBM, TRM is not called upon, tracked or reserved nor is it possible to do so. TRM is simply a margin that would, in theory, be sufficient such that reasonable deviations from the system conditions modeled when ATC was calculated would not result in unscheduled operator actions and/or curtailment of transactions. If EPSA has specific recommendation on how to monitor and report the utilization of TRM please file a SAR to modify the standard to include those.

Organization/Group	Question 5 Comments:
Transparency: The standard requires full transparency among reliability entities. However, NAESB is the appropriate entity to developing any standards related to transparency for market participants. Consistency: The standard creates consistency in the way an entity must report, update and describe its TRM. The MOD standards as a group also insure that TRM is applied consistently to all customers. The standard does not establish a consistent (universal) TRM across all regions. Transmission systems vary between regions and even within a region. Applying a universal TRM would, due to the nature of the transmission systems, be detrimental to either reliability, market access, or and more likely both. Undue Discrimination: The consistency required by the standard will prevent a utility from undue discrimination since the TRM applies to all users of a path, not just one particular user. Overall if the commenter has recommended text for the standard please submit a SAR to further modify the standard.	
NERC RTOSDT	The Real Time Operation Standards Drafting Team is concerned that the proposed MOD standards do not include any reference to the Planning and Operating Limits mandated by the current FAC, IRO and TOP standards. These standards already include transmission flow limits both in the longer term planning time frame as well as the shorter term operating time frame. The proposed MOD standards seem to be establishing procedures to calculate the commercial boundaries without a direct link to the required reliability boundaries. MOD-001 R6 states that the TTC "use assumptions" no more limiting than those used in planning. The RTO SDT would ask shouldn't TTCs be required to be "no less limiting" than the SOLs / IROLs computed for the system? Current NERC standards are not just asset limits, they are also system limits. The current standards require that limits be calculated that recognize both local and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eliminating) the MOD standards to the current SOLs / IROLs requirements, the Industry would be more correctly linking how the system MUST BE operated to any NAESB business practice. Indeed it would seem that current tariffs are based on the computations used in current planning and operating environments. By using the current SOL / IROL limits the procedural / prescriptive requirement in MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IRO requirements)The questions for the ATC SDT:? How do these MOD standards relate to the SOLs / IROLs? Why should these ATC/TTC limits be decoupled from the SOLs / IROLs? Shouldn't the long-term SOL / IROL limits computed in Planning be the TTC for the system (or at least the basis for the TTC)? Shouldn't the short-term SOL / IROL be the basis for the ATC for the system? MOD-008 computes margins. By coordinating the MOD standards with the SOL / IROL standards, the only Business (not NERC) requirement may be to define the options on how the TSP could couple the various SOL / IROL values that it obtains from its RCs and TOPs. MOD-028 By using SOLs / IROLs there would be no need to get into ATC / AFC "methodologies". Indeed standards that include "alternatives" are not defining a single "standard approach". But by using specific planning and operating limits the

Organization/Group	Question 5 Comments:
	methodologies become irrelevant. The “limit” becomes explicit and well-defined. Any margins or variations about those limits would then be obvious and transparent. What is most important is respecting the reliability-based limits and not how the commercial value is computed. If this idea of using SOLs / IROLs as the limit(s) or at least the basis for those commercial limits, then the TSP becomes a coordinator of which values to use for the commercial periods. The TSP would not be the computer of those limits. Thus MOD-028 could become a business practice for posting ? rather than a standard for computations.
Response: This comment does not raise any questions related to MOD-008. The SDT agrees that MOD-008 computes margins. Please see the response to this question in the responses to comments for the other MOD standards.	
NPCC Regional Standards Committee	The language in the Proposed Effective Date should be modified to be consistent with the other standards
Response: TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions.	
FirstEnergy	FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal comment period based on the prior initial ballot feedback. We commend the team for moving quickly to respond to the ballot comments and providing the industry a revised set of standards to review and comment. **Response:** Thank you for your supportive comment. Regarding the revision to the Effective Date, while FirstEnergy agrees that there is a need to ensure that the standard is implemented consistently across the entire continent we are concerned with the Effective Date being subject to approval of ALL regulatory authorities. We believe an appropriate Implementation Plan should reflect a period of time beyond the NERC Board of Trustee approval date that would reflect when the requirements are considered mandatory and enforceable. The timeline should allow sufficient time for regulatory authority reviews, with the intent of sanctions also being enforced in conjunction with the conclusion of the implementation period. However, a delay from a given regulatory agency should not impact when the requirements are considered mandatory and enforceable for the bulk electric system. **Response:** TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions.
Response: Please see in-line responses.	
Duke Energy Corporation	Implementation Plan – Since R2 and M2 link the TRM calculation methodology with the CBM methodology in MOD-004, implementation dates for these standards should be aligned. **Response:** The SDT has modified the measure to address this concern.

Organization/Group	Question 5 Comments:
	Since R2 and M2 link the TRM calculation methodology with the CBM methodology in MOD-004, the Standards Drafting Team must avoid creating a duplicate requirement the CBM standard, which could subject entities to multiple penalties for the same violation. **Response:** The CBM standard does not have a similar requirement, so there is no potential for multiple penalties for the same violation.
Response: Please see in-line responses.	
Bonneville Power	BPA respectfully submits the following observations and suggestions: a. The sixth component of uncertainty listed in R1.1 should be expanded as follows: - Variations in generation dispatch (including forced or unplanned outages, maintenance outages, and location of future generation) **Response:** Bullet #3 and #6 were modified based on this comment to read “Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages). “Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).” .b. To comply with FERC Order 890 transparency requirements, R1.5 should not be removed (e.g. “ If TRM is not used, a statement of that practice.”) – BPA believes a Transmission Operator should be required to provide a robust justification as to why it is not using TRM in it’s ATC or AFC calculations. **Response:** The applicability makes this standard apply only to those entities that maintain TRM. At this time the SDT is not requiring an entity to document that they don’t use or need TRM. c. A new R6 should be added that clearly states the timeframe in which TRM is to be used (i.e. within the hour). **Response:** Unlike CBM, TRM is not called upon, tracked or reserved. TRM is simply a margin that would, in theory, be sufficient that reasonable deviations from the system conditions modeled when ATC was calculated would not result in unscheduled operator actions and/or curtailment of transactions. d. The Time Horizons listed for all requirements should include the “Long-term Planning” Horizon, as TRM is to be calculated beyond the seasonal window. **Response:** The use of “Time Horizons” in this standard is in the form of a compliance element, and refers to the manner in which compliance evaluates the implications of a violation of the standard. In this context, time horizon has to do with the

<table>
<tr><th>Organization/Group</th><th>Question 5 Comments:</th></tr>
<tr><td></td><td>urgency of addressing a violation, e.g., how quickly a violation needs to be rectified. Together, the Violation Risk Factor and Time Horizon aid a compliance auditor in determining sanctions. Accordingly, the SDT believes that the appropriate horizon for compliances does not include “Long-term Planning.”

e. Balancing Authorities may be appropriately identified as Applicable Entities in this MOD and request that the Standards Drafting Team provide an explanation as to why they are not listed.
Response: Only Transmission Operator’s are assigned requirements in this standard and therefore they are the only applicable entity.</td></tr>
<tr><td colspan="2">Response: See imbedded Responses.</td></tr>
<tr><td>Oncor Electric Delivery</td><td>This standard should not apply to ERCOT for the reason expressed in question 2.</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard.

Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>ISO RTO Council/Standards Review Committee (SRC)</td><td>Although the SDT had the appropriate Team to establish a default percentage for TRM, the FERC deadline did not allow enough time to complete this portion of the requirement. Since TRM is a reliability margin, the IRC encourages the Team to provide what ever input it currently has in a 'parking lot' for a possible future Team to undertake the development activity. There should be a default percentage to be used without requiring specific documentation, work papers and load flow cases if a straight percentage such as 5% is used. Additional information would be required only if a greater percentage is used.</td></tr>
<tr><td colspan="2">Response: The drafting team in numerous discussions examined the use of a fixed percentage rather then specifying the areas on uncertainty. The standard as it is currently written does not require or forbid the use of a fixed percentage as a margin, but does require that the entity explain the rationale for the percentage. Additionally the standard requires that the margin represent only the areas of uncertainty specified in R1 and not include any items included in CBM. We encourage the ISO RTO Council to draft a SAR if further development in TRM is desired.</td></tr>
<tr><td>MRO NERC</td><td>1. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO</td></tr>
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Organization/Group	Question 5 Comments:
Standards Review Subcommittee	believes the eventual standard that is approved will serve the industry and customers better as a result **Response:** Thank you for your supportive comment. 2. The MRO believes that the first time you use an abbreviation or acronym, you must spell out the full term followed by the abbreviation or acronym in brackets. Subsequent use of the term is then made by its abbreviation or acronym. **Response:** The team agrees that abbreviations or acronyms should generally not be used until defined, but was unable to find an instance of this in the standard. If you are referencing "ATC Path," that is a defined term and therefore not an acronym or abbreviation.
Response: Please see in-line responses.	
Ontario IESO	The language in the Proposed Effective Date should be modified to be consistent with the other standards
Response: TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions.	
Hydro One Networks	Language in the Proposed Effective Date should be modified to be consistent with the other standards, e.g. MOD-001-1
Response: TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions.	
American Transmission Company	The first time that each abbreviation or acronym is introduced, the full terminology should be stated followed by the abbreviation or acronym in brackets (i.e. ATC). **Response:** The team agrees that abbreviations or acronyms should generally not be used until defined, but was unable to find an instance of this in the standard. If you are referencing "ATC Path," that is a defined term and therefore not an acronym or abbreviation. The Proposed Effective Date for MOD-008-1 is different then that written for MOD-001-1. Why the difference in the Effective Date? **Response:** TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions. We do not believe that the SDT has to provide a definition of TRMID. Requirement 1 outlines the specifics of TRMID and we find the definition unnecessary. The SDT should explain why this definition is necessary and what if anything is it including that the requirement does not already contain. **Response:** The team believes the definition is helpful, and was asked by a previous commenter to provide a definition. Additionally, the term may be used in NAESB Business Practices.

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<tr><th>Organization/Group</th><th>Question 5 Comments:</th></tr>
<tr><td>Texas-New Mexico Power company</td><td>This standard should not apply to ERCOT for the reason expressed in question 2.</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard.

Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>Brazos Electric Power Cooperative, Inc.</td><td>Brazos Electric believes that for a TOP operating in a single-control area region like ERCOT that the establishment of TRM may have no reliability benefits. The Applicability Section 4.1 for MOD-008 as written in this draft states "Transmission Operators that maintain TRM" could possibly be interpreted that this applies only to those TOPs who have a need to establish TRM because of the region it operates in. Otherwise in R1 it is recommended that an "if applicable" clause be inserted to address this issue.</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard.

Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>Electric Service Delivery</td><td>These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a</td></tr>
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Organization/Group	Question 5 Comments:
	Single Balancing Authority under Nodal market design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. Applicable definitions: According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: ?A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows? TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. CBM is defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Comments: ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch element designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch.MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT.MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculation. Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT.MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable.MOD-029-1 covers Rated System Path Methodology, which is used to calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT.MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT.ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to dispatch individual generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a

Organization/Group	Question 5 Comments:
	Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations.
Response: **Response:** This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	
Orlando Utilities Commission	Requirements 1, 3, 4 and 5 are great exactly as they are. They are a good balance of standardization, disclosure and recognition that different parts of the transmission system function differently and are most sensitive to different factors. **Response:** Thank you for your supportive comment. For Requirement #2, what is the reliability purpose for limiting the items that an entity can consider when establishing TRM? **Response:** Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The order also directed that the standard specify that TRM not include elements of CBM.
Response: Please see in-line responses.	
Gainesville Regional Utilities	None at this time.