Consideration of Comments on Real-time Operations Standards — Project 2007-03

The Real-time Operations Standard Drafting Team thanks all commenters who submitted comments on the third draft of the standards for Real-Time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from August 25, 2009 through September 24, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 26 sets of comments, including comments from more than 80 different people from over 45 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Changes have been made to the project standards as indicated below due to industry comments and miscellaneous updates:

Minor wordsmithing was done to TOP-001-2, Requirement R1 to add 'identified' to Reliability Directive so that there can be no confusion – the listed functional entities are only responsible for 'identified' Reliability Directives.

Requirement R2 was added to TOP-001-2 to allow a responsible entity to inform the Transmission Operator is it is unable to perform a Reliability Directive.

TOP-001-2, Requirement R3 was altered to tie the cited Emergencies to those noted in the assessment of the Operational Planning Analysis. This ties down the 'known or expected' language that caused some entities concern.

The Generator Operator was removed from TOP-001-2, Requirement R5 based on comments received which indicated that the Generator Operator did not posses the knowledge to participate in the required actions. This requirement was also changed to use the defined terms "Adverse Reliability Impact" to clarify what 'reliability impact' was involved and "Transmission Operator Areas" to clarify the portion of the BES involved.

TOP-001-2, Requirement R6 was added. This requirement is currently TOP-003-0, Requirement R3. The SDT believed that this requirement was going to be handled by another SDT and had originally deleted it from Project 2007-03. However, that is no longer the case and it is being added back in at this time.

TOP-001-2, Requirement R7 has had clarifying language added to show that the System Operating Limits identified in Requirement R8 are part of this requirement.

Requirement R8 of TOP-001-2 has been altered to indicate that the System Operating Limits cited will have been identified in the Operational Planning Analysis required in TOP-002-3, Requirement R1.

TOP-001-2, Requirement R9 was added to accommodate the addition of System Operating Limits in Requirement R8 similar to what was done in Requirement R7 for IROLs.

TOP-001-2, Requirement R10 has had some minor wordsmithing changes for additional clarity.

TOP-001-2, Requirement R11 has been clarified to indicate the System Operating Limits identified in Requirement R8 must be included here as well.

Requirements R12 through R14 have been added to TOP-001-2 to address a FERC Order 693 directive on minimum capabilities for Transmission Operators. Originally this directive was going to be handled by Project 2009-02, Real-time Reliability Monitoring and Analysis Capabilities but that project is now on indefinite hold so the need to address the directive has returned to Project 2007-03.

The VSL's for Requirements R3, R5, R8, and R10 of TOP-001-2 have been adjusted to align with the most recent VSL guidelines.

TOP-002-3, Requirement R1 was altered to make use of a defined term 'Operational Planning Analysis' that clearly shows the intent of what is required. A rationale text box was added to describe the reasoning for this change. TOP-002-3, Requirement R2 has been clarified to show that the System Operating Limits discussed in TOP-001-2 are included here.

Data retention for TOP-002-3 has been modified to agree with the latest guidelines.

The VSL's for TOP-002-3, Requirement R3 have been adjusted to align with the latest guidelines.

TOP-003-2, Requirements R1 and R5 have been changed to align with the addition of 'Operational Planning Analysis' in TOP-002-3.

TOP-003-2, Requirement R3 has been clarified so that monitoring and status are both explicitly included.

Measure M5 of TOP-003-2 has been changed to more clearly state what evidence is required.

The VSL's for Requirements R2 and R3 of TOP-003-2 have been changed to align with the latest guidelines.

Due to the number of comments received requesting an additional posting, and the number of changes made to the revised standards, the SDT agrees that an additional posting is required, however the team also recommends that this posting take place in parallel with an initial ballot.

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Greg Mason	Dynegy Generation	NPCC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
17.	Bruce Metruck	New York Power Authority	NPCC	6
18.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
19.	Robert Pellegrini	The United Illuminating Company	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
22.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		SERC	5
2.	Mike Garton		NPCC	6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Gerald Beckerle, Vice Chair - SERC Operating Committee	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Neagle	AECI	SERC	1, 3, 5
2.	Gene Delk	SCE&G	SERC	1, 3, 5
3.	J. T. Wood	Southern	SERC	1, 3, 5
4.	Steve Fritz	ACES Power Marketing	SERC	6
5.	Alan Jones	Alcoa	SERC	1, 5
6.	Hugh Francis	Southern	SERC	1, 3, 5
7.	Bob Dalrymple	TVA	SERC	1, 3, 5, 9
8.	Chad Randall	E.ON.US	SERC	1, 3, 5
9.	George Carruba	EKPC	SERC	1, 3, 5
10.	Brad Young	E.ON.US	SERC	1, 3, 5
11.	Timmy LeJeune	Louisiana Generating	SERC	1, 3, 6
12.	John Troha	SERC Reliability Corp.	SERC	10

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

Additional Member	Additional Organization	Region	Segment Selection

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Anita LEE	AESO	WECC	2
2.	Lourdes ESTRADA-SALINERO	CAISO	WECC	2
3.	H. Steven MYERS	ERCOT	ERCOT	2
4.	Matt GOLDBERG	ISO-NE	NPCC	2
5.	Bill PHILLIPS	MISO	RFC	2
6.	Jim CASTLE	NYISO	NPCC	2
7.	Patrick BROWN	PJM	RFC	2
8.	Charles YEUNG	SPP	SPP	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FirstEnergy	RFC	
2.	Dave Folk	FirstEnergy	RFC	
3.	John Reed	FirstEnergy	RFC	
4.	John Martinez	FirstEnergy	RFC	
5.	Andy Hunter	FirstEnergy	RFC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Deb Schaneman	Platte River Power Authority Operations Group	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Baker	Platte River Power Authority	WECC	1, 3, 5
2.	John Collins	Platte River Power Authority	WECC	1, 3, 5
3.	John Powell	Platte River Power Authority	WECC	1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Transmission Technical Operations	WECC	1
2.	Tim Loepker	Transmission Dispatch	WECC	1
3.	Rebecca Berdahl	Power Long Term Sales & Purchases	WECC	3

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS Corporation	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
4.	Ken Goldsmith	Alliant Energy	MRO	4
5.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Jason L Marshall	Midwest ISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Thomas	Illinois Municipal Electric Agency	SERC	4
2.	Joe O'brien	NIPSCO	RFC	1
3.	Barb Kedrowski	We Energies	RFC	3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	Michael Davis	WECC RC										X
11.	Individual	Hugh Francis	Southern Company	X		X		X					
12.	Individual	James A Maenner	James A Maenner								X		
13.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
14.	Individual	Ed Stein	self								X		
15.	Individual	Michael Ayotte	ITC Holdings	X									
16.	Individual	Mike Gentry	Salt River Project	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
18.	Individual	Larry Watt	Lakeland Electric	X		X		X					
19.	Individual	Daniel Herring	The Detroit Edison Company			X	X	X					
20.	Individual	Howard Rulf	We Energies			X	X	X					
21.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
22.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
23.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
24.	Individual	Martin Bauer	US Bureau of Reclamation					X					
25.	Individual	Jason Shaver	American Transmission Organization	X									
26.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. TOP-001-2: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: A number of comments were received requesting clarification of terminology or intent within the various requirements. The SDT has answered all of the comments and made a number of the requested changes as shown below. However, no changes were made as to content or context of the requirements.

Due to industry comments, the following changes were made to the standard:

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

R8. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.

M1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, , evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M3. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M5. Each Transmission Operator shall make available upon request, evidence that operations it coordinated its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5 unless conditions did not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5%	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more

	the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**
R10 VSL	N/A	N/A	N/A	The Transmission Operator did inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL as identified in Requirement R8, has been exceeded.

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	No	(1) In R1, reliability directive is capitalized in indicating (or implying) it is a defined term. But this term has not yet been defined despite our understanding that there are currently three SDTs that are reviewing and/or attempting to define this term and the term (Directive). We suggest to make this term lower case until it is defined. (2) R2: the revised wording seems a bit odd as the phrase “expected to be affected” could be interpreted to be describing the actual or anticipated Emergency conditions. We suggest R2 to be revised to: “Each Transmission Operator shall inform its Reliability Coordinator and known or expected to be affected Transmission Operators of actual Emergency and anticipated Emergency conditions” to enhance clarity. Alternatively, we propose inserting a comma after “expected to be affected”. (3) R3: We suggestion to add a comma after “comparable emergency procedures”. (4) R5 to R8: The very issue that we brought up during the last 2 postings came under the spot light with the changes made at this posting. The SDT in response to industry comments made changes to qualify the SOLs whose exceedances are to be reported (in R7) based on a list of SOLs identified in R6 (the SDT added this requirement for this reason). While we don’t think such identification is necessary, and in fact may expose the system to unreliability since such a list would be selective and hence bound to miss some SOLs that affect reliability, we nevertheless are encouraged by the changes and the addition since it is a step in the right

Organization	Yes or No	Question 1 Comment
		direction. In our view though, it did not go far enough. However, without an explicit requirement that the TOP shall operate within all SOLs (as in the case for IROL in R5) and to act or direct others to act to mitigate the magnitude and duration of exceeding all SOL within some time frame (as in the case for IROL in R8), the requirements to identify a list of SOLs (in R6) and informing its Reliability Coordinator of actions being taken to return the system to within limits when one of these SOLs has been exceeded (in R7), appear inconsistent. We therefore recommend that R5 be altered as follows:R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL Tv, and each other System Operating Limit (SOL) and its associated time period as determined by the TOP. Similar to their IROL counterparts, operating within all SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations, although for IROLs the interconnected system impact is readily obvious than for SOLs. The same principle holds true for day-ahead operational planning so that the needed control measures can be identified and made available in advance to prevent operating in excess of SOLs and to mitigate exceedances if and when they occur during day at hand and real-time operations. (5) As pointed out in our previous comments, we did not agree that VSLs should be determined based on the number of times a requirement was violated. While it is appropriate to determine the VSLs for R6 based on the number of SOLs that support local area reliability not reported to the RC since these numbers represent the extent of missing the total set, the same approach should not be applied to the determination of R7 since the progressive VSLs appear to make a difference between IROL and SOL (Note: the former has a Severe VSL for failing to notify one exceedance whereas for the latter the VSLs are graded based on the number of SOLs whose exceedances a TOP failed to notify its RC). Note that R7 requires that the TOP inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. The requirement does not make any distinction between IROL and SOL, and requires that there shall not be even a single incident that the TOP does not inform its RC of actions being taken to mitigate an IROL or SOL exceedance. Hence, missing even one SOL would violate the bulk of the intent of R7. We suggest the VSLs for Low, Moderate and High be removed, and revise the VSL for Severe to:The Transmission Operator did not make available evidence that it had informed itsReliability Coordinator of actions being taken to return the system to within limit when an IROL or SOL has been exceeded.
Northeast Power Coordinating Council	No	(1) In R1, reliability directive is capitalized in indicating (or implying) it is a defined term. But this term has not yet been defined despite our understanding that there are currently three SDTs that are reviewing and/or attempting to define this term and the term (Directive). We suggest to make this term lower case until it is defined. (2) R2: the revised wording seems a bit odd as the phrase “expected to be affected” could be interpreted to be describing the actual or anticipated Emergency conditions. We suggest R2 to be revised to: “Each Transmission Operator shall inform its Reliability Coordinator and known or expected to be affected Transmission Operators of actual Emergency and anticipated Emergency conditions” to enhance clarity.

Organization	Yes or No	Question 1 Comment
		Alternatively, we propose inserting a comma after “expected to be affected”. (3) R3: Add a comma after “comparable emergency procedures”. (4)Similar to their IROL counterparts, operating within all SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations. (5) As pointed out in our previous comments, we did not agree that VSLs should be determined based on the number of times a requirement was violated. While it is appropriate to determine the VSLs for R6 based on the number of SOLs that support local area reliability not reported to the RC since these numbers represent the extent of missing the total set, the same approach should not be applied to the determination of R7 since the progressive VSLs appear to make a difference between IROL and SOL(Note: the former has a Severe VSL for failing to notify one exceedance whereas for the latter the VSLs are graded based on the number of SOLs whose exceedances a TOP failed to notify its RC). Note that R7 requires that the TOP inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. The requirement does not make any distinction between IROL and SOL, and requires that there shall not be even a single incident that the TOP does not inform its RC of actions being taken to mitigate an IROL or SOL exceedance. Hence, missing even one SOL would violate the bulk of the intent of R7. We suggest the VSLs for Low, Moderate and High be removed, and revise the VSL for Severe to:The Transmission Operator did not make available evidence that it had informed itsReliability Coordinator of actions being taken to return the system to within limit when an IROL or SOL has been exceeded.

Response: (1) Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.

> **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

(2) The SDT has revised Requirement R2 (now Requirement R3) based on your comments and the comments of others.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

(3) The comma has been added as suggested. (Note – Requirement R3 is now Requirement R4.)

> **R4**. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

(4) The SDT agrees that operating within a certain subset of SOLs such as IROLs is fundamental to reliability. However, the SDT does not believe operating within all SOLs is necessary and actually reduces reliability by eliminating an operator’s operational flexibility such as reducing the life of a piece of equipment

Organization	Yes or No	Question 1 Comment

to avoid shedding firm end use Load. However, the SDT realizes that there may be a certain set of SOLs that are considered important by the Transmission Operator and that would be treated in a similar vein to IROLs. The new Requirement R9 addresses this concern.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.

(5) The SDT has reviewed the various VSLs to assure that they follow the latest guidelines and has revised several of them accordingly. Examples are shown below.

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**
R10 VSL	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL as identified in Requirement R8, has been exceeded.

MRO NERC Standards Review Subcommittee	No	A. In R4, states that the TOP and GOP shall coordinate operations “known or expected” by the TOP that have a reliability impact on other reliability entities. Is the TOP used twice in this requirement the same TOP or neighboring TOPs? Please clarify. B. In R4, the GOP will not know of “known or expected” operations of the TOP. Please clarify. C. In R4, as stated the GOP is required to notify the TOP of “relay and equipment failure and changes to generation”, does this include all relays and all equipment associated with a generator? D. In R4, the reference to the term “Load”, a TOP and GOP don’t have loads. Therefore, how can they be

Organization	Yes or No	Question 1 Comment
		required to coordinate something they don't have? Or E. In R4, the reference to the term "operating conditions", the GOP may not know of a severe or changing "operating condition" that is taking place on the transmission system. F. In R2 and R4, "expected to be affected" would include known. Please strike known. G. Both R5 and R6 require the TOP to identify a sub-set of SOLs that may be larger than the IROL subset ahead of time and notify the RC of what actions it is taking to return the system to within operating limits when they are exceeded. Why is there not a requirement to also operate within those SOLs and return within the SOL if exceeded? H. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages?I. The measures for R5 and R8 need to be clear than they currently are that these are event driven requirements and only data is required if an "event" has occurred.

Response: (A) This is the same Transmission Operator.

(B) The SDT agrees that the Generator Operator will not know of operations on the BES. The requirement has been deleted.

(C) This would include all relays and equipment that could impact the Bulk Electric System. Requirement R4 (now Requirement R5) has been changed to provide greater clarity as to the intent of the requirement.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

(D) A Transmission Operator must be able to forecast and monitor the Load on its portion of the Bulk Electric System. They must be aware of significant changes that could cause changes to expected Load. No change made.

(E) The SDT agrees that the Generator Operator will not know of operations on the BES. The requirement has been deleted.

(F) The SDT disagrees and feels that both terms are needed but has added terminology to clarify the expectation. (Note – Requirement R4 is now Requirement R5.)

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

(G) By definition, IROLs could result in cascading outages, widespread outages, and blackouts. SOLs will not. Thus, the SDT believes that requiring the

Organization	Yes or No	Question 1 Comment
Transmission Operator to operate within all SOLs that are not IROLs would eliminate the Transmission Operator's operational flexibility. However, the SDT realizes that there may be a certain set of SOLs that are considered important by the Transmission Operator and that would be treated in a similar vein to IROLs. The new Requirement R9 addresses this concern. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. (H) The SDT has reviewed the VSLs for Requirement R8 and revised them based on the latest guidelines.		

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**

Bonneville Power Administration	No	Comments: The term "Reliability Directive" needs to be added to the NERC Glossary of Terms (it was not in the April 2009 version).
Platte River Power Authority Operations Group	Yes	In R1 Reliability Directive is capitalized as a defined term but isn't in the NERC Glossary of Terms or Definitions or the Terms Used in Standard section of version 2 of the standard. Where is this term defined?
IRC Standards Review Committee	No	Requirement 1: Reliability Directive, as a defined term has been introduced and the definition has not been provided in this posting. If the intent is to use this as a defined term anticipating that it will be defined and approved soon under a different project, then we suggest these standards not be put up for balloting until the term is approved.
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		

Organization	Yes or No	Question 1 Comment
Ed Stein - self	No	I do agree with most every thing However I do not understand what is meant by the phrase "expected to affect" a TO. How does the TO experiencing the emergency know if his emergency affect every TO. Granted he should know of the main ones but can he be sure that a remote line is affected that has a 2-5% response factor.
Response: The SDT has made a clarifying change to the requirement which should alleviate your concern. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.		
ITC Holdings	No	In R2, strike the words "known or". In R4, remove the added words "by the Transmission Operator" from the second sentence . The addition of this phrase implies that the Generator Operator does have the obligation to initiate the coordination of changes in generation with the transmission operator. The requirement is clearer without this phrase. In R4, change the wording to "Such operations MAY include"? We believe the intent of the sentence was only to provide a list of examples. R6 requires the TOP to identify a sub-set of SOLs that is larger than IROLS and "support its local area reliability". It is unclear what criteria a TOP would use to identify this subset, which will lead to inconsistent implementation and confusion. The TOP should inform the RC of all SOLs and the actions being taken to address any SOL exceedance which can be accomplished via SCADA or other means of action and communication when necessary. The measures for R5 and R8 need to be clear that these are event driven requirements and only evidence is required if an "event" has occurred.
Response: The SDT feels that the term 'known' has a different connotation than 'expected' and therefore both are required. However, the SDT has made clarifying changes so that expectations are clear. . **R3.** Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. The SDT agrees with the second suggestion for Requirement R4 (now Requirement R5) and has made that change. However, the SDT does not agree with the deletion of Transmission Operator that was suggested and has retained it in the requirement. **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission		

Organization	Yes or No	Question 1 Comment
Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. Based on comments received during the first and second posting, the industry did not reach a consensus that all SOL exceedances should be reported. The majority (it was a small majority) of responders felt that some subset of SOL exceedances should be reported. They felt the subset should be greater than IROLs but less than all SOLs. The remaining respondents were split between only IROLs and all SOLs. This split was likely based on the differing characteristics of the BES in various areas. Thus, the SDT felt drafting the requirement as is represented a reasonable compromise because the Transmission Operators could report the appropriate amount of SOLs based on the characteristics of their portion of the BES. Few additional comments have been received on this issue during this posting, thus the SDT assumes the industry largely agrees this is a reasonable compromise. The SDT feels that the measures are clear as written and has not made a change.		
SERC OC Standards Review Group	No	Is Reliability Directive a defined term since it is capitalized in R1 and throughout the Standard, but not currently found in the NERC Glossary of Terms. R2 We suggest that “other transmission operators” should be changed to “adjacent transmission operators”. R3 What is specifically meant by the words, “emergency assistance”? For example, do the words as written require a utility to provide line crews to assist in storm restoration? We suggest that the language be tightened up to focus emergency assistance on those things that were intended by the language. R4 we suggest removing “and Generator Operator” and the term “by the Transmission Operator” from the first sentence. It appears that the original wording implies that the Generator Operator would have knowledge of conditions on the transmission system. We also suggest removing the last sentence listing some but not all items that may have operating impacts and in which communications is necessary, concerns the SERC OC Standards Review Group. R6 We suggest revising R6 to read: Each Transmission Operator shall inform its Reliability Coordinator of any System Operating Limits (SOLs) which, while not IROLs, will require mitigating actions if exceeded. The current word “all” seems to indicate that every SOL would be in this list. R8 Why is R8 needed ? it appears to be a duplication of R5 and the two could be combined. General comment on measures: Measures that are event driven need to be clear that evidence would only be required if an event occurred. That is, the entity should not have to prove a negative.
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		

Organization	Yes or No	Question 1 Comment
The SDT discussed and felt that it is possible that some Transmission Operators could affect one another even if they are not adjacent as a result of sharing ties. Thus, no change has been made. R3 – Emergency assistance is not a defined term and could be different from entity to entity. The SDT can't define this term and doesn't feel that it is necessary. Each Transmission Operator will respond according to its set policies and procedures as required by EOP-001-2. No change made. The SDT agrees that the Generator Operator will not know of operations on the BES. However, the Generator Operator may know that his unit is critical to reliability. If his unit is critical to reliability, the SDT expects the Generator Operator should notify the Transmission Operator of all known issues that could reasonably be expected to cause the unit to be at a greater likelihood to be forced out. In Requirement R4 (now requirement R5), the SDT has modified the listing to reflect that it is not all inclusive based on comments from other respondents. **R5**. Each Transmission Operator shall coordinate its respective operations known or expected to have a Burden on the portion of the BES of other reliability entities with those entities unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, Load, or operating conditions. The SDT has modified the wording of Requirement R6 (now Requirement R8) to provide greater clarity. **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.** Requirements R5 & R8 (now Requirements R7 & R10) are slightly different and thus serve slightly different reliability goals. Requirement R7 (now Requirement R8) requires the Transmission Operator to operate within an IROL. Requirement R10 (now Requirement R11), however, requires the Transmission Operator to mitigate an exceedance if one has occurred. For example: If an exceedance occurs and goes away on its own within T_v, there is no violation of Requirement R7. However, if that exceedance occurs and the Transmission Operator doesn't act to mitigate it within T_v then they are in violation of Requirement R10. No change made. The SDT feels that the measures are clear as written and has not made a change in this regard.		
American Electric Power	No	It's our understanding that a definition of the term for a Reliability Directive (RD) may be currently under development/review/approval. However, since RD is not currently found in the NERC glossary, we request that it be added to the definition section of this standard. For example, are base points issued by the market area of an RTO considered an RD? Is there a method to distinguish such base points as constituting an RD from those that are not RDs? The team correctly capitalizes "Transmission" and "Load" since they are terms included in the NERC dictionary and does not capitalize "generation" since it is not included. It would seem that adding the term to NERC glossary would be the best resolution, but, in the interim, it should be well defined within the context that it is being used in any requirement (refer to R4). We are concerned that R5 is a duplication of a requirement in FAC-009 and perhaps others as well. Correspondingly, M5 would also be duplicative. Again, it appears that R6 may be duplicative of FAC-014, R5.2. If not, the phrase "support its local area reliability" should be clarified.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>While we appreciate the team’s efforts to better distinguish IROLs from SOLs in R7., more work is necessary to better define the difference. (e.g., exceeding limits vs. n-1)</td></tr>
<tr><td colspan="3"> Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.
Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.
The SDT does not believe this is a duplication of the FAC-009 requirements. While many SOLs will be based on a facility rating, not all SOLs are based on facility ratings. Thus, the requirement is needed.
The SDT does not feel that this requirement duplicates FAC-014 as the requirement is specific to those SOLs that are in support of local reliability. The SDT has clarified Requirement R8 to make it clear how the SOLs are identified.
R8. Each Transmission Operator shall inform it’s Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis.
IROLs are a defined subset of SOLs. The SDT believes that the FAC-011-2 and FAC-014-2 standards provide a great amount of detail to distinguish IROLs from SOLs. </td></tr>
<tr><td>American Transmission Organization</td><td>No</td><td> No requirement to define IROL TV. R6 is already covered in the MOD standards. </td></tr>
<tr><td colspan="3"> Response: FAC-014-2, Requirement R5.1.2 requires the Reliability Coordinator to identify the IROL T_V. No change made.
The SDT does not believe that Requirement R6 (now Requirement R9) is covered in the MOD standards. The SDT feels that you may have meant FAC-014-2. The SDT does not feel that this requirement duplicates FAC-014 as the requirement is specific to those SOLs that are in support of local reliability. The SDT has clarified Requirement R8 to make it clear how the SOLs are identified.
R8. Each Transmission Operator shall inform it’s Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis. </td></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td> R.4 - The changes suggested to R. 4 are too vague to result in effective coordination.
What is meant by “expected relay failures”? How is an expected relay failure assessed? What criteria is used to determine what we consider a risk of an expected relay failure - what conditions?
R.6 - is again too vague for making consistent operating decisions. What criteria is applied for identifying SOL’s that support “local area reliability”? What is a local area, how large is it, what reliability criteria is violated on the violation of an SOL </td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		R.7 – SOL's identified in R6 are vague.

Response: The intent of Requirement R4 (now Requirement R5) was to require coordination. The SDT has made clarifying changes to the requirement.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. .

Relay failures were cited as an example of conditions that may require coordination. The wording was changed to state 'may' apply so if you have nothing that applies to this condition, you do not have to coordinate them. No change made for this comment but clarifying language was applied.

> **R5**. Each Transmission Operator shall coordinate its respective operations known or expected to have a Burden on the portion of the BES of other reliability entities with those entities unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, Load, or operating conditions.

The SDT has clarified Requirement R8 to make it clear how the SOLs are identified.

> **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.**

Organization	Yes or No	Question 1 Comment
Electric Market Policy	No	R1 - By capitalizing the term "Reliability Directive", the SDT introduced a discrepancy as this term does not currently exist in the NERC Glossary of Terms. We are opposed to approving revisions to existing or new standards when they are predicated upon references to other "draft" terms, standards, requirements, etc. R4 We have reviewed the various comments made concerning retention of GOP in this requirement, and philosophically agree but find it impossible to determine how GOP can coordinate" its respective operations known or expected by the Transmission Operator to have a reliability impact". without knowing what constitutes "expected to have a reliability impact". The GOP can only coordinate to the extent the TOP has provided predefined information that is required to be coordinated. This information should be included in the Interconnection Agreement or some other agreement that clearly spells out what the GOP is expected to communicate in order to coordinate. We would prefer inclusion of this requirement in TOP-003 as part of R4 (referencing R2 and R3) or we could support the requirement in TOP-001 if it referenced coordination of data required in TOP-003 @ R2 and R3. Also the statement"operating conditions" is sufficiently vague. The SDT needs to clarify what constitutes an operating condition?

Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the

Organization	Yes or No	Question 1 Comment
recipient is necessary to address an actual or expected Emergency. The SDT agrees and has deleted the requirement. The wording was changed to state 'may' apply so if you have nothing that applies to this condition, you do not have to coordinate them. **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.		
Xcel Energy	No	R1- There is not an associated definition for the term Reliability Directive (nor is there one in the documents associated with Project 2006-06). The term "directive" is the subject of much debate as evidenced by the recent attempt at clarification by the NERC advisory on communications. This term needs to be defined and an opportunity for stakeholder comment, prior to moving this standard to ballot. R1- We feel that GOP should be removed from this requirement. The TOP should coordinate with any entity it necessary. Alternatively, it could be reworded to read: "The TOP shall coordinate operations with the GOP". R2- Should be redrafted to read: "Each Transmission Operator shall inform its Reliability Coordinator and other impacted Transmission Operators of actual or anticipated Emergency conditions."Alternatively, this requirement could be abbreviated to have the TOP notify the RC, as the sharing of that condition by the RC to other impacted entities is covered by the proposed project 2006-06, IRO-001-2 R4: "Each Reliability Coordinator that identifies an expected or actual threat with Adverse Reliability Impacts, within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area." R3- Though addressed in the previous draft version, we continue to disagree with retaining this requirement. Determining if the other entity has implemented a comparable emergency procedure places the burden upon the entity providing assistance to verify completion of internal processes by the requesting entity. This is not reasonable or practical in an emergency situation, and requires the operator to make a subjective decision. Additionally, assuming the requesting entity is compliant with the NERC standards (e.g. EOP-002), there is no reason for the assisting entity to confirm that the deficient entity has properly implemented their comparable procedure. R4- The term "reliability impact" is vague. In reality, every change on the system has a reliability impact, whether it be positive or negative. We recommend instead using the phrase "adverse reliability impact". To what degree must operations be coordinated? The proposed requirement indicates that changes in generation and Load must be coordinated. Does this mean changes in dispatch levels of every generator must be coordinated? How are changes in Load coordinated and what would constitute a significant change worthy of coordination? We recommend striking the last sentence that indicates examples. R5- This implies that the "Interconnection" will specify the IROL Tv. The NERC Glossary defines this at <= 30

Organization	Yes or No	Question 1 Comment
		minutes. Are there IROL Tvs <= 30 minutes? If not, why not just eliminate the hassle of trying to define and keep up with the IROL Tv and just state < 30 minutes in this requirement (and remove the IROL Tv definition)? R8- The phrase "within the IROL's Tv" should be deleted. The TOP should be directing others to act regardless of whether or not the elapsed time is within or exceeded the IROL Tv. 1.4. Data RetentionThe data retention section implies that compliance is to the Measure as well as the Requirement. We believe that compliance is measured to the Requirement only.

Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

Your second comment regarding Requirement R1 does not appear to be consistent with the requirement. Your comment appears to assume that Requirement R1 is focused on coordination but rather the requirement is for the Generator Operator among others to follow the Transmission Operator's Reliability Directives. No change made.

The SDT agrees that there is some confusion created by the wording of the requirement and has modified the requirement based on the comments of other respondents in an attempt to provide greater clarity. However, the SDT did not adopt the term 'impacted'.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

The SDT disagrees with your comment regarding Requirement R3 (now Requirement R4). Requirement R3 (now Requirement R4) provides the Transmission Operator the option of not providing emergency assistance if the requesting Transmission Operator has not implemented comparable procedures. It does not require the assisting Transmission Operator to verify that the requesting Transmission Operator has implemented comparable procedures. The assisting Transmission Operator could simply provide emergency assistance rather than verifying the requesting Transmission Operator has not implemented its procedures. While the SDT does not favor inclusion of the comparable procedures language, the respondents in previous postings overwhelmingly desired the inclusion. It does not cause a reliability gap so the SDT cannot identify a reason not to include it. No change made.

R4 – The SDT has changed Requirement R4 (now Requirement R5) to provide greater clarity based on your comment and that of others.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

R5 – Earlier standards work determined that the previous definition of IROL was not satisfactory and that the T_v definition was needed to improve the meaning. The SDT does not see a need to remove the definition. Further, the removal of the definition would expand the scope of the SDT beyond the Transmission Operator standards and is not warranted.

Organization	Yes or No	Question 1 Comment
R8 (now Requirement R11) – The SDT agrees the Transmission Operator should be acting with expediency to resolve an IROL. The requirement does not allow the Transmission Operator to wait to resolve the IROL exceedance but rather recognizes that the Transmission Operator requires time to assess how to resolve the exceedance. Assessing is one form of acting and the language of the requirement is appropriate as it is written. No change made. Data retention – The language in the data retention section is standard verbiage that simply states that you must retain the data necessary to measure the compliance with the requirement. No change made.		
FirstEnergy	No	R3 This requirement requires "comparable emergency procedures" be implemented which is appropriate and consistent with the previous standards, but it lacks, and the previous standards lacked, the concept of mitigation. An entity should not be required to shed load for the sake of requiring a neighboring entity to shed load to mitigate the emergency condition. As currently written, in order for an entity to require its neighbor to shed load that will mitigate the emergency condition, the requesting entity is required to shed load first. We suggest this be revised to say, "comparable emergency procedures that mitigate (lessen or eliminate) the impact of the emergency." R6 This requirement is ambiguous. By definition a System Operating Limit is "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: (a) Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)? Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)? Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)? System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"As written, the TOP will be required to inform the RC of all equipment ratings that "support local area reliability." This could be interpreted as requiring an entity to report equipment ratings for facilities operated at 100 kV or less which we believe is not the intent of the SDT. These facilities certainly support local area reliability on some level but are not monitored by the RC and serve little or no value to the RC.FAC-014-2 requires the TOP in Req. R2 to "establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." Therefore, it appears that TOP-001-2 Req. R6 may not be necessary. However, if the intent of FAC-014-2 Req. R2 is to establish SOLs from an Operations PLANNING horizon (not sure since FAC-014-2 does not include time horizons with the requirements), and the intent of TOP-001-2 Req. R6 is to inform the RC from a REAL-TIME operations horizon, then Req. R6 of TOP-001-2 should be consistent with FAC-014 and written as follows: "R6. Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which are consistent with its Reliability Coordinator's SOL methodology."
Response: R3 – The SDT has modified the requirement (now Requirement R4) in response to other commenters. **R4**. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or		

Organization	Yes or No	Question 1 Comment
statutory requirements. R6 – Based on comments from other respondents, the SDT has modified Requirement R5 to use “Burden” rather than reliability impact. The SDT believes this will lessen your concern that facilities below 100 kV are included. Further, the SDT believes this issue is largely an issue around the definition of BES. Standards apply only to the BES and facilities impactive to the BES. Defining the BES is beyond the scope of this SDT. The SDT believes that FAC-014-2, Requirement R2 covers the operating horizon as well. The intent of Requirement R9 is not to duplicate FAC-014-2, Requirement R2 but for the Transmission Operator to identify the subset of SOLs from FAC-014-2, Requirement R2 that impact local area reliability to the point that the Reliability Coordinator may need to become involved. Thus, the Transmission Operator would communicate to the Reliability Coordinator SOL exceedances for this subset of SOLs. The SDT has made a clarifying change to Requirement R6 (now Requirement R8). **R8**. Each Transmission Operator shall inform it’s Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.**		
Duke Energy	No	The definition of “Reliability Directive” drafted by the Reliability Coordination SDT should also be commented on in this TOP effort. We are concerned that the definition is too broad and would encompass what we consider normal communications. A key point of the definition should be that each communication of a Reliability Directive is required to be identified as such to the receiving entity. R2 should say that the TOP shall inform its RC and direct interconnected TOPs. The phrase “known or expected to be affected” opens the TOP to non-compliance if they don’t expect someone to be affected, and it turns out that they are affected. R3 strike the phrase “provided that the requesting entity has implemented its comparable emergency procedures”. In this situation we should not be wasting time getting proof that the requester has implemented their procedures before rendering assistance. R4 is confusing. Relay and equipment failures are not operations; they are operating events. Also, what is meant by the phrase “unless conditions do not permit such coordination” R5 is confusing and appears to duplicate R8. Delete R8 and reword R5 as follows: “Each Transmission Operator shall operate or direct others to operate within IROL Tv for each identified Interconnection Reliability Operating Limit (IROL).” R6 should include identified IROLs in the communication to the RC. Reword R6 as follows: “Each Transmission Operator shall inform its Reliability Coordinator of all identified IROLs and those System Operating Limits (SOLs) which support its local area reliability.” Revise Measures and VSLs to reflect these changes to TOP-001-2
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.		

Organization	Yes or No	Question 1 Comment
Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency. R2 – (now Requirement R3) The SDT disagrees that only directly interconnected Transmission Operators should be included. It is possible that a Transmission Operator could be adversely impacted by another Transmission Operator that is not directly interconnected. Furthermore, the SDT has made a clarifying change to the requirement wording. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. R3 **-** While the SDT does not favor inclusion of the comparable procedures language, the respondents in previous postings overwhelmingly desired the inclusion. It does not cause a reliability gap so the SDT cannot identify a reason not to include it. R4 – (now Requirement R5) Relay failures were cited as an example of conditions that may require coordination. The wording was changed to state 'may' apply so if you have nothing that applies to this condition, you do not have to coordinate them. **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. The phrase "unless conditions do not permit such coordination" was intended to cover any situation that may prevent coordination from occurring up front. One example that may prevent coordination would be the need to take emergency actions such as ordering a unit to re-dispatch to relieve an IROL. Requirements R5 & R8 (now Requirements R8 & R11) are slightly different and thus serve slightly different reliability goals. Requirement R8 requires the Transmission Operator to operate within an IROL. Requirement R11, however, requires the Transmission Operator to mitigate an exceedance if one has occurred. For example: If an exceedance occurs and goes away on its own within T_v, there is no violation of Requirement R8. However, if that exceedance occurs and the Transmission Operator doesn't act to mitigate it within T_v then they are in violation of Requirement R11. No change made. R6 (now Requirement R9) – IROL exceedances would be covered under Requirement R3 as they would represent an emergency condition. No change made. VSLs and Measures have been revised as necessary.		
Southern Company	No	The measure for R2 does not carry forth the definition of which other TOP should be informed. R2 requires informing other TOPs that are expected to be affected. The measurement requires that contact was made with all TOPs that were affected. The list of TOPs that are expected to be affected before the fact may be different than the list of TOPs that actually were affected.Would suggest minor change in R2 from "Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions" to "Transmission Operators known or expected to be affected of actual Emergency or anticipated Emergency conditions" The second "each" in M1 and M4 should be deleted. Would suggest modifying VSL for M5 to read in the same tense of the Measure. Specifically, instead of "The Transmission Operator did not operate within an identified" to "The Transmission Operator operated outside

Organization	Yes or No	Question 1 Comment
		an identified”
Response: The SDT agrees that there is some confusion created by the wording of the requirement and has modified the requirement based on the comments by you and other respondents in an attempt to provide greater clarity. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. **M3**. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. The SDT agrees that the second each in M1 and M5 should be deleted and has modified the measures accordingly. **M1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, in accordance with Requirement R1, evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. **M5.** Each Transmission Operator shall make available upon request, evidence that operations it coordinated its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5 unless conditions did not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. While the proposed modification to Measure M6 is one way to write the VSL, the SDT does not see an issue with the way the VSL is currently modified and has left it unchanged.		
US Bureau of Reclamation	No	The proposed addition of the term 'by the Transmission Operator" makes the Transmission Operator the reliability entity the exclusive source for determining when operations are expected to have a known or expected reliability impact on other reliability entities. This would eliminate the Generator Operator's ability to determine which operations can have an impact on other reliability entities such as Transmision Operators.The response from the SDT clearly indicated that "further the SDT recognizes that the scope and number of individual agreements, which may be needed to ensure that all operations are fully coordinated for all operations known or expected to have a reliability impact upon other Reliability Entities is highly likely to vary greatly from region to region or organizational arrangement to organizational arrangement. If the Transmission Operator is to be the exlusive source for the determination of those operations have or are expected to have a reliability impact on other reliability entities, then a separate requirement and measure is needed to ensure that such a determination is properly conveyed to the Generator Operator. Prior to this addition, the Generator Operator was able to make the operational impact assessment. The SDT should

Organization	Yes or No	Question 1 Comment
		either create a new requirement for the TOP to provide to the Generator Operators the operations that have or are expected to have impacts on reliability entities or alter the language that the reliability entities determine when their respective operations impact other realiability entities.
Response: The SDT agrees that the Generator Operator will not know of operations on the BES and has deleted the requirement.		
Midwest ISO Standards Collaborators	No	We largely agree with the requirements but have a few suggestions.In R2 and R4, “expected to be affected” would include known. Please strike known. R5 and R6 require the TOP to identify a sub-set of SOLs that may be larger than the IROL subset ahead of time and to notify the RC of what actions it is taking to return the system to within operating limits when they are exceeded. Why is there not a requirement to also operate within those SOLs and return within the SOL if exceeded? The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for R5 and R8 need to be clear that these are event driven requirements and only evidence is required if an “event” has occurred.

Response: The SDT feels that the term ‘known’ has a different connotation than ‘expected’ and therefore both are required. No change made.

The SDT determined that the Reliability Coordinator should be notified when the SOLs in Requirements R5 and R6 (now Requirements R8 & R9) are exceeded so that the assessor can be situationally aware and assess the need for additional action. At the same time, the SDT did not want to limit the operational flexibility of a Transmission Operator to temporarily exceed an SOL by a slight amount to avoid having to take drastic actions such as shedding load unnecessarily. No change made.

The SDT has reviewed all of the VSLs based on the latest guidelines and made changes accordingly. The R10 VSL is an example of such changes.

R10 VSL	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL has been exceeded

The SDT feels that the measures are clear as written and has not made a change.

Organization	Yes or No	Question 1 Comment
WECC RC	No	What is definition for when an SOL supports or does not support Local Area Reliabilty?

Organization	Yes or No	Question 1 Comment
		Is this for 100kV and above? What are the timing requirements for returning elements to a level below their SOL?
Response: The SDT has changed Requirement R8 to clarify this issue. **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.** The Reliability Standards are for the BES which is 100 kV and above unless specific exceptions are noted in the Applicability Section. Timing requirements would be based on the specific SOL characteristic such as if it is based on a facility thermal rating.		
James A Maenner	Yes	
Lakeland Electric	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		

2. TOP-002-3: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: Industry comments centered on requests for clarification from the SDT. The SDT has responded to these comments and made changes as noted below.

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.

R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.

Data retention - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling 90 day period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	No	(1) We continue to disagree with the way R2 is worded. R1 requires a TOP to conduct next day analysis to assess if any of the SOLs will be exceeded. R2 requires that the TOP develop plans to preclude operating in excess of only the IROLs identified as a result of the assessment performed in R1. Given our stance on this issue and understanding that IROLs represent a subset of SOLs, we believe R2 should be changed to refer to SOLs. In our view, a TOP needs to conduct next day analysis to assess if any of the established limits will be exceeded, develop plans to preclude operating in excess of the IROLs and SOLs, and make resources and actions available for mitigating exceedances if and when they occur. Like operating within SOL sand IROLs, this is fundamental to reliable operation. We suggest R2 be revised to include all SOLs.
Response: In response to your comment and those of others, the SDT has made a change to Requirement R2 to include certain, qualified SOLs that have been identified as needed for local are reliability. **R2**. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Northeast Power Coordinating Council	No	(1) We continue to disagree with the way R2 is worded. R1 requires a TOP to conduct next day analysis to assess if any of the SOLs will be exceeded. R2 requires that the TOP develop plans to preclude operating in excess of only the IROLs identified as a result of the assessment performed in R1. Given our stance on this issue and understanding that IROLs represent a subset of SOLs, we believe R2 should be changed to SOL. In our view, a TOP needs to conduct next day analysis to assess if any of the established limits will be exceeded, develop plans to preclude operating in excess of the IROLs and SOLs, and make resources and actions available for mitigating exceedances if and when they occur. Like operating within SOLs and

Organization	Yes or No	Question 2 Comment
		IROLs, this is fundamental to reliable operation. We suggest R2 be revised to include all SOLs. (2) Remove “single” from R1.
Response: (1) In response to your comment and those of others, the SDT has made a change to Requirement R2 to include certain, qualified SOLs that have been identified as needed for local are reliability. **R2**. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. (2) The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. However, the SDT has made a clarifying change to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Bonneville Power Administration	No	Comments: Change R1 wording. "R1:The wording is still incorrect in our interpretation. The wording needs to be changed to state that an assessment of the next days planned study conditions SOL'S is still valid with the expected next day’s conditions. The previous wording isn’t realistic because many days the assessment could determine a contingency response would cause the in place SOL to be exceeded. Some contingencies require the SOL to be lowered to prepare for the next condition which would cause real-time system readjustment. And the next contingency and the next contingency ?. Some days the assessment would say the SOL could be exceeded for HLH. The key to those SOL'S is that the SOL'S are set at a level where the worst contingency for that path would not cause the interconnection to go unstable, i.e. cascading outages.. Suggest clarifying what is meant by “their” in R3:”Each Transmission Operator shall notify all reliability entities identified in theplan(s) cited in Requirement R2 as to their role in the plan(s).” Perhaps state “their role in the TOP’s Plans”.
Response: The SDT believes Requirement R1 as drafted aligns with the interpretation for TOP-002-2a, Requirement R11. However, the SDT has made clarifying changes to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. ‘Their’ refers to the antecedent all reliability entities. The SDT finds no additional clarity from the proposed wording change. No change made.		
Platte River Power Authority Operations Group	No	Is "an assessment" consistent with the interpretation of TOP-002-2 R11 by Orlando Utilities Commission or are you requiring a real-time contingency analysis tool?We believe there should be no requirements for the TOP to have a real-time contingency analysis tool if the BA and RC have the tool and model the TOP's system.

Organization	Yes or No	Question 2 Comment
Response: The SDT has made clarifying changes to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Duke Energy	No	R1 , M1 and Data Retention could be interpreted to require that daily assessments (which could include a dated Power Flow) will have to be kept for 6 months. This could take up a lot of space. R2 as worded gives the impression that an IROL will be identified during a daily assessment respecting an SOL per R1. First, if you respect the SOL there will be no IROL. Second, simple day-ahead studies with an online Power Flow looking for contingencies might not identify an IROL. It might, but you would probably need to examine some multiple contingencies before something would cascade. R2 could be revised to read that each TOP shall plan to preclude operating in excess of any identified IROL's during the day-ahead assessment per R1. Also, maybe this requirement should be an RC requirement.
Response: The SDT agrees with your concern and has changed the data retention to 90 days. **Data retention** - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling 90 day period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. R2. Requirement R2 requires an entity to compare SOLs/IROLs to flows and to identify any new SOLs/IROLs as needed. The SDT does not see that any additional clarity would be gained by the change of wording suggested for Requirement R2. No change made.		
WECC RC	No	R2 should include SOLs. In R3 the plan should be shared with the RC.
Response: The SDT believes SOL are local in nature and as such do not require a plan. When correctly identified, operating outside or exceeding a SOL will only harm the entity exceeding the SOL, not the Interconnection. R3. The Reliability Coordinator is a functional entity and is thus covered by the existing wording. No change made.		
IRC Standards Review Committee	No	Requirement #1: It is not clear why we introduce 'single' Contingency event since a TOP may be required to study multiple contingencies identified by its RC (See FAC-011-2, Requirement R3). A better term may be "Continegency events identified in FAC-011."
Response: The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. However, the SDT has made clarifying change to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		

Organization	Yes or No	Question 2 Comment
Salt River Project	No	
Response: Without specific comments, the SDT is unable to provide a response.		
Xcel Energy	Yes	R1- Is there a need to specify IROLs as well?
Response: IROLs are addressed in TOP-002-3, Requirement R2.		
Lakeland Electric	Yes	Requirement R-1 and Measure M-1 require modification for clarity. Replacing the undefined term "assessment" with the NERC defined term "Operational Planning Assessment" throughout the TOP-002-3 standard will help to clarify both line items. Using "Operational Planning Analysis" in measure M-1 clarifies that the power flow study does not have to be performed day-ahead (see the definition of Operational Planning Analysis). This is in-line with the recent interpretation issued by NERC discussed in the appendix of TOP-002-2a. Using "Operational Planning Analysis" in requirement R-1 ensures the planner understands that his or her assessment is meant to be more than just a determination of System Operating Limits. Requirement R-1 would also benefit from clarifying "single Contingency event." Current day-ahead contingency analysis is limited to determining system performance during single transmission line, generator and transformer outages. However, using "single Contingency event" could include lightning struck towers with two or more transmission lines or even bus failures at which multiple transmission lines terminate. Unless it is the intent of the standard team to increase the scope of TOP-002 I recommend finishing requirement R-1 with ". . . involving transmission lines, transformers, and generators."
Response: Operational Planning Assessment is not a currently defined term. The SDT believes that you meant 'Operational Planning Analysis and agrees and has made the change. The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. FAC-011-2 Requirement R3.3 already requires a Reliability Coordinator to determine SOLs from a list of multiple Contingencies that the Planning Coordinator identifies per FAC-014-2, Requirement R6 as having Stability limits. To remove the word single here would only cause confusion if additional multiple Contingencies over and above those used to identify SOLs in FAC-011-2, Requirement R3.3 are required to be tested. They are not required or needed for reliability. No change made in this regard. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Entergy Services, Inc	Yes	This standard seems to conflict with MOD-001, Requirement 7. This standard requires that: When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. When applying the requirements from TOP-002-3 along with the MOD-001 standard, it seems that all TSP's will need to calculate ATC or AFC up to the calculated IROL for the time

Organization	Yes or No	Question 2 Comment
		period. When the two standards are looked at independently they are fine, when you look at both, there is some confusion on where NERC wants the TSP's to go.
Response: TOP-002-3 is not applicable to Transmission Service Providers and the SDT does not see any conflict. MOD-001, Requirement R7 requires AFC/ATC/TTC studies to use no more limiting assumptions than what is used in real-time studies, i.e., the Transmission Operator sets the limits and the Transmission Service Provider follows. No change made.		
American Electric Power	Yes	
American Transmission Organization	Yes	
Ed Stein - self	Yes	
Electric Market Policy	Yes	
FirstEnergy	Yes	
ITC Holdings	Yes	
James A Maenner	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
SERC OC Standards Review Group	Yes	
Southern Company	Yes	
The Detroit Edison Company	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your response.		

3. TOP-003-1: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: Due to industry comments, the following clarifying changes were made:

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

Part 1.1, last bullet: Operating parameters for equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

Part 1.3 A periodicity for providing data.

Part 1.4 The deadline by which the respondent is to provide the indicated data.

R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. . The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled.

Organization	Yes or No	Question 3 Comment
WECC RC	No	Is mutually agreeable a formal process? Should it be in writing? The RC should be involved because of the numerous formats it has to deal with.
Response: The SDT used the phrase 'mutually agreeable' because it did not feel it would be necessary to have one format that fits all, nor do it feel it would be feasible to do so. The SDT feels that this phrasing allows the entities involved the flexibility they need to make this happen and therefore does not believe that the process needs to be formal or in writing but recognizes that entities are not prevented from doing so**.** The requirement is clear that the specification must be 'documented.' The Reliability Coordinator is not required to be directly involved. This requirement is focused on the Transmission Operator and Balancing Authority receiving the date they need to perform their function to meet the NERC reliability requirements. Any data that the Transmission Operator or Balancing Authority needs to collect because the Reliability Coordinator requires the data from them is likely to be included in this list. Reliability Coordinator requirements are covered in the IRO family of standards**.**		
SERC OC Standards Review Group	No	R1 Does "specification for data" mean a complete listing of data points or a listing of types of data required for different types of facilities such as "generation, transmission, etc." Also, does this standard apply solely to internal requirements of a BA and its TOP? The concern is the multiple types of formats that may be required in order to exchange data with an expanded list of entities external to the BA or TOP.

Organization	Yes or No	Question 3 Comment
		M5 measurements should be modeled similar to the measurement in M4, in particular, that last sentence of M4. Is TOP-003-2 a new standard utilizing an existing number? If so, does the previous TOP-003-1, Planned Outage Coordination have to be retired? The migration from the current TOP-003-1 to the new TOP-003-2 seems like it could cause confusion. Would it be better to just retire TOP-003-1 and form a new standard number like TOP-011-1? R4 and R5: Should there be a time requirement for complying with a data request?
Response: The specification for data is intended to ensure the Transmission Operator and Balancing Authority have the data they need to complete their functional responsibilities. A complete listing of the data points or a listing of the types of data required would both seem to allow the Transmission Operator and Balancing Authority to specify the data they need to complete their function responsibilities. M5 measures**:** The SDT agrees with your suggestion and has modified Measure M5 as shown below. **M5.** Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. . The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled. TOP-003-1 will be retired as per the Implementation Plan filed for this project. The numbering scheme for standards is controlled by the NERC Standards Process Manager and is not in the scope of the SDT. R4 and R5: The data specification required by Requirement R1 includes, per part 1.3, a timeframe and periodicity of the data. To clarify this, the SDT has broken this out into 2 distinct parts. **Part 1.3** A periodicity for providing data. **Part 1.4** The deadline by which the respondent is to provide the indicated data.		
Southern Company	No	R1 is written for the Operations Planning timeframe. As such, would suggest rewording “shall have a documented specification for data necessary for Real-time monitoring and reliability assessments” to “shall have a documented specification for data necessary for reliability assessments and Real-time monitoring”. Having “Real-time monitoring” mentioned first may convey the impression that “Real-time” also applies to the reliability assessments. Also, would suggest rewording “Equipment at voltage levels lower than” to “Outages of equipment at voltage levels lower than.”
Response: The SDT has made clarifying changes to the wording of the requirement. **R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.		

Organization	Yes or No	Question 3 Comment
The SDT has clarified the wording for this part in response to your comment. **Part 1.1, last bullet**: Operating parameters for equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.		
Xcel Energy	No	R5- We are concerned that this may be liberally applied to require entities to provide data to other entities with no clear reliability need. We feel this requirement could place extreme and unnecessary burden on entities to provide data in a specified format and time interval.
Response: The SDT believes that the requirement is reasonable in that requests must fall within the parameters of the data specifications provided by each entity. No change made**.**		
Bonneville Power Administration	No	Regarding M4 (last sentence): “The evidence shall be that there are noTransmission Operators as identified in Requirement R2 or Balancing Authorities asidentified in Requirement R3 with outstanding requests for data to the subject entitythat have been unfilled”.This doesn't mention the "TIMEFRAME" response time to provide data after a request is made. (i.e. 30 days, 60 days or whatever the reasonable "TIMEFRAME" is to modify databases or communication channels.) The VSL should be adjusted accordingly. If an entity has just received a request and is being audited the next week before fulfilling the request that would be a SEVERE VSL, which seems inappropriate.
Response: The SDT has clarified Parts 1.3 and 1.4 to address your concerns. **Part 1.3** A periodicity for providing data. **Part 1.4** The deadline by which the respondent is to provide the indicated data.		
Duke Energy	No	The data specification in R1 is broad and could force a company to name every breaker, voltage point, MW point, etc. on their system. Perhaps an ICCP document or something similar could be used, but it’s not clear as the requirement is currently written. Also, this standard goes into a lot of detail in R1 through R4. This standard could be simply one requirement, R5.
Response: The specification for data is intended to ensure the Transmission Operator and Balancing Authority have the data they need to complete their functional responsibilities. A complete listing of the data points or a listing of the types of data required would both seem to allow the Transmission Operator and Balancing Authority to specify the data they need to complete their function responsibilities. The SDT believes that the requirements, as written, are correct and lend themselves more readily to measurement.		
US Bureau of Reclamation	No	The modification of the language related to data specifications creates a potential for compliance violation for the

Organization	Yes or No	Question 3 Comment
		reliaibility entities other than the Transmission Operator. The specifications for data " necessary for Real-time monitoring and reliability assessments" needs to be more expicit. The language allows it to be below the BES voltage threshold. This is coupled with the requirement that no outstanding requests for rata from the transmission operator are unfilled. This double negative is easier to restate that all data requests from the transmission operator must be filled. This is very open ended. Should the data request is unreasonable, the other reliability entities would be non-compliant. The data specification need to be subject to review and approval by the Reliability Coordinator in the case of conflict brought by the reliabilty entity. The requirement, in case of conflict, would not be invoked until the data specifications are approved. This opportunity for appeal of the specifications ensures transmission operators apply technical reasoning in developing the specifications.
Response: The SDT disagrees with your assessment. Part 1.3 has been changed and Part 1,4 added to address your concern. Part 1.2 requires a mutually agreeable format. Requirement R4 requires the entities receiving the data specification to provide it in a format that they agreed upon which includes the timeframe. **Part 1.3** A periodicity for providing data. **Part 1.4** The deadline by which the respondent is to provide the indicated data.		
MRO NERC Standards Review Subcommittee	No	The term "Long term outages" in the first sub bullet is not clear, please clarify.
American Electric Power	Yes	AEP would appreciate that the reference to "Long term outages" in R1.1.1. be specified in terms of the time elapsed.
Response: The Transmission Operator and Balancing Authority will have to define what long term outages are in their data specification. They could be different for various Transmission Operators and Balancing Authorities so no set time frame can be selected. No change made.		
Northeast Power Coordinating Council	Yes	Regarding R4, M4, it does not appear to be warranted that a Generator Owner, Generator Operator, Interchange Authority, or Load-Serving Entity provide evidence that there are no outstanding requests for data. As the originator of the request, the evidence that there are no outstanding requests for data should be provided by the Balancing Authority or Transmission Operator, as applicable.
Response: The SDT is addressing the need to show evidence without introducing the need to "prove a negative". If no outstanding request for data can be found, then compliance exists. If there has indeed been a request, but the entity has not provided the data, the requester will likely provide a complaint and a copy of the request. An attestation that all requests have been fulfilled may suffice. No change made**.**		
FirstEnergy	Yes	We agree with the changes to TOP-003-1. However, we feel that R3 should be re-written to be consistent with the wording in R2. We suggest a change as follows: "R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide

Organization	Yes or No	Question 3 Comment
		Facility status to the Balancing Authority."
Response: The SDT agrees with your suggestion and has changed the Requirement R3 wording to be consistent with the sequence contained in Requirement R2. **R3**. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.		
American Transmission Organization	Yes	
Ed Stein - self	Yes	
Electric Market Policy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
ITC Holdings	Yes	
James A Maenner	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		

4. **TOP-004-3: Do you agree with the decision to move the lone remaining requirement of this standard to TOP-001-2? If not, please supply specific reasons why you do not agree with this move.**

Summary Consideration: All respondents agreed with this change.

Organization	Yes or No	Question 4 Comment
American Electric Power	Yes	
American Transmission Organization	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Ed Stein - self	Yes	
Electric Market Policy	Yes	
FirstEnergy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
ITC Holdings	Yes	
James A Maenner	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 4 Comment
Council		
Platte River Power Authority Operations Group	Yes	
Salt River Project	Yes	
SERC OC Standards Review Group	Yes	
Southern Company	Yes	
The Detroit Edison Company	Yes	
US Bureau of Reclamation	Yes	
WECC RC	Yes	
Xcel Energy	Yes	
NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your response.		

5. TOP-001-2, Requirement R1: Do you believe that the Balancing Authority issues Reliability Directives directly for transmission-related limits and therefore should be in the TOP standards,(vote YES); or do you believe that the Balancing Authority in its role as a Balancing Authority issues Reliability Directives to balance load and generation and only indirectly affects transmission flows (recognizing that an entity that serves as both a Transmission Operator and a Balancing Authority would be covered under the Transmission Operator requirement) (Vote NO). Please be as specific as possible with your reply.

Summary Consideration: The overwhelming majority of respondents 'voted' No to this question which validates the position of the SDT. Thus, no changes were necessary.

Organization	Yes or No	Question 5 Comment
SERC OC Standards Review Group		We are unsure how to respond to this question as it pertains to TOP-001-2, R1.
Electric Market Policy	No	
Xcel Energy	No	
ITC Holdings	No	Balancing Authorities do not operate transmission. They would only issue requirements with regard to capacity and energy emergencies.
Midwest ISO Standards Collaborators	No	Balancing Authorities do not operate transmission. They would only issue requirements with regard to capacity and energy emergencies.
James A Maenner	No	BAs that neither own nor operate transmission should not issue reliability directives for transmission-related limits. Without the tools and knowledge of a Transmission Operator, the BA could isssue conflicting orders to the TOP's operating plans. Certainly, the BA should relay a TOP directive but not be the initiator.
Manitoba Hydro	No	The BA is responsible to operate its generation assets within the reliability constraints established by the Transmission Operator and Reliability Coordinator.
Independent Electricity System Operator	No	The BA's role is to balance load-generation-interchange and does not have any direct role in monitoring and operating system conditions within transmission-related limits.
Northeast Power Coordinating Council	No	The BA's role is to balance load-generation-interchange and does not have any direct role in monitoring and operating system conditions within transmission-related limits.

Organization	Yes or No	Question 5 Comment
IRC Standards Review Committee	No	The BA's role is to balance load-generation-interchange only; it does not have any direct role in monitoring and operating system conditions within transmission-related limits.
Platte River Power Authority Operations Group	No	The Transmission Operator issues the "Transmission" reliability directive and the Balancing Authority issues directives to balance the generation to load.
Bonneville Power Administration	No	Transmission-related issues are the responsibility of the TOP not the BA.
The Detroit Edison Company	No	We believe that the Balancing Authority in its role as a Balancing Authority issues Reliability Directives to balance load and generation and only indirectly affects transmission flows and should not be in the TOP standards.
WECC RC	No	In WECC, the RC deals mainly with the BAs. The BAs with their responsibility to maintain load and resources, ACE, and frequency places them in a position to direct and control all other activities on the interconnection. The RC expects the BAs to accomplish and direct actions to restore or mitigate contingencies in the interconnection.
Southern Company	No	TOP-001-2 does not mention any entity except for the Transmission Operator as issuing Reliability Directives.Yes, it is appropriate for the Balancing Authority to issue Reliability Directives that are related to his responsibilities (issues regarding balance load and generation), but there should be no confusion that the Reliability Coordinator has ultimate authority and thus could issues overriding Reliability Directives. The definition of a Balancing Authority in the NERC Glossary is, "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." This definition gives them no responsibility for transmission limits. However, the Balancing Authority does need to be able to give Reliability Directives in order to aid in the resolution of transmission-related limit problems.
We Energies	No	We Energies joined MISO's comments for this project. We have one additional comment for this question. The BA may need to issue Directives to Generator Operators or Distribution Providers in response to a TOP or RC need to resolve a transmission issue. Basically "pass-through" the Directive from the TOP or RC to the entity that will actually carry out the directed action.
Response: Thank you for your response.		
American Transmission Organization	No	Because the team is use the term Reliability Directive our answer may depend on what how this term is finally defined. We believe that the term needs to be defined and approved by skateholders prior to this standard being posted for balloting.

Organization	Yes or No	Question 5 Comment
US Bureau of Reclamation	No	The term "Reliability Directive is not a defined term. The question is poorly worded since the TOP-001-2 R1 specifically reserves the reliability directive to Tranmission Operator for this standard. The Balancing Authority does not issue directives. It works within its capacity and emergency plan to aleviate imbalances. After implementing all of its remedies the Balancing authority works through the reliability coordinator. The Reliability Coordinator may declare an emergency and take specific actions. See the refercences below:EOP 002 - R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.R5. . The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.R6 If the Balancing Authority cannot comply with the Control Performance andDisturbance Control Standards, then it shall immediately implement remedies to do so.These remedies include, but are not limited to:R6.1. Loading all available generating capacity.R6.2. Deploying all available operating reserve.R6.3. Interrupting interruptible load and exports.R6.4. Requesting emergency assistance from other Balancing Authorities.R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:R7.1. Manually shed firm load without delay to return its ACE to zero; andR7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."R8. A Reliability Coordinator that has any Balancing Authority within its ReliabilityCoordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
NERC Standards Review Subcommittee	No	The MRO NSRS believes any directives that a BA may issue should be in the BAL standards. R1, states that a BA, DP, LSE, and GOP shall comply with a Reliability Directive issued by a TOP. Reliability Directive is not defined by NERC. A definition has not been proposed.
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		
American Electric Power	Yes	Even in conditions where the BA is providing RDs to balance load and generation, the changes may still impact the BES. Under such circumstances, there remains a need for the BA to be aware of loadings on the BES.

Organization	Yes or No	Question 5 Comment
Duke Energy	Yes	The BA is involved in generation dispatch, which directly affects transmission flows.
Response: The Balancing Authority does not directly originate Directives to alleviate Transmission issues. They only respond to what they are told by the Reliability Coordinator or Transmission Operator. The majority of commenters agree with this position. No change made.		
FirstEnergy	Yes	The question as written is confusing based on the present wording of TOP-001-2 R1. Nevertheless, we believe that the Balancing Authority (BA) should be applicable in the TOP-001-2 standard and that their role as stated in R1 is correct. The BA receives direction from the TOP when redispatch solutions are needed to alleviate transmission-related limits (i.e. voltage, thermal, etc).
Ed Stein - self	Yes	
Lakeland Electric	Yes	
Response: Thank you for your response.		

6. Do you agree that with the changes in the 3rd posting that this project is ready to go to ballot? If not, please supply specific reasons why not.

Summary Consideration: No changes were made to requirements as a result of the comments received to this question. However, due to the number of comments received requesting an additional posting, and the number of changes made to the revised standards, the SDT agrees that an additional posting is required.

Organization	Yes or No	Question 6 Comment
Southern Company		Additional clarification per our previous comments is required. Re-posting may not be required.
Ed Stein - self	No	Due to my earlier response
Electric Market Policy	No	See comments above
WECC RC	No	See previous comments.
SERC OC Standards Review Group	No	See the above comments.Note: The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
ITC Holdings	No	The comments on TOP-001-2, particularly in regard to R6, need to be resolved before balloting.
Response: Please see the responses to previous comments.		
IRC Standards Review Committee	No	(1) The SRC is concerned that the absence of an explicit requirement for operating within SOLs may be problematic. Operating within SOLs is an important operating practice that will position the system to be stable within the acceptable reliability criteria included in the definition of SOLs and the requirements to be included in the methodology that is used to determine SOLs.The SRC recognizes that SOLs cover the full range from minor localized limits through Interconnection Operating Reliability Limits (IROLs), and that SOLs are defined to respect the facility and equipment ratings that are included in the determination of the values of SOLs. The suggested requirement R6 in TOP-001-2 for a TOP to identify SOLs, for which the TOP is to notify the RC when the SOLs are exceeded, is intended to address those SOLs that, while not meeting the definition of IROLs, may have potential impact that is important from a local viewpoint. Although these SOLs may not cause an impact equivalent to or greater than that in the definition of Adverse Reliability Impact, they deserve additional attention, including monitoring and notifications between TOPs and RCs. If the SDT holds the view that operating within the identified SOLs and correcting their exceedances are implicit and precursory to R7 and R8, then we would

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>suggest to make it explicit by revising R5, by saying, for example: R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL Tv, and each System Operating Limit (SOL) as identified in R6 and its associated time period as determined by the TOP. Similar to their IROL counterparts, operating within SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations, although for IROLs the interconnected system impact is readily obvious compared to the SOLs. The same principle holds true for day-ahead operational planning so that the needed control measures can be identified and made available in advance to prevent operating in excess of SOLs and to mitigate exceedances if and when they occur during day at hand and real-time operations. To this end, we suggest the SDT consider revising R2 of TOP-002-3 to: "Each Transmission Operator shall plan to preclude operating in excess of those System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) identified as a result of the assessment performed in Requirement R1."

(2) Also there is concern that a definition for Reliability Directive has not been determined and agreed upon through the standards development process. Until such time that the definition of Reliability Directive can be developed and agreed to, the references to Reliability Directives or these standards should not go to ballot.</td></tr>
<tr><td colspan="3">Response: The SDT agrees that operating within a certain subset of SOLs such as IROLs is fundamental to reliability and has made changes throughout TOP-001-2 and TOP-002-3 accordingly.

(2) Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.</td></tr>
<tr><td>NERC Standards Review Subcommittee</td><td>No</td><td>A. A Reliability Directive must be defined and there must be an opportunity to comment before balloting can begin.

B. Our responses to the previous questions are additional reasons why this standard should not go to ballot and that this standard needs another comment period.</td></tr>
<tr><td colspan="3">Response: A. Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

B. The SDT agrees that one more draft and posting is necessary.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
American Electric Power	No	AEP believes that one more draft is needed to verify that key edits provided by stakeholders during this round are included before proceeding to ballot.
Response: The SDT agrees that one more posting is necessary..		
Manitoba Hydro	No	Changes are still required to TOP-001-2
Response: The SDT has made changes to TOP-001-2 and agrees that one more posting is necessary.		
American Transmission Organization	No	Changes needed to remove R6 from draft TOP-001-2 and to include a requirement to establish TV for all IROL's.
Response: Requirement R6 (now Requirement R8) was added in response to substantial industry comments received in the second posting and remains in the proposed standard. FAC-014-2, Requirement R5.1.2 requires the Reliability Coordinator to identify the IROL T_v. No change made.		
Bonneville Power Administration	No	Correct R1 to assess the SOL is proper, not that the SOL could be exceeded. Where does the seasonal planning operations coordination described in TOP-002-2 R3 go? Re: the MOD-001-1 proposal.
Response: The SDT does not understand the comment nor is it able to see a correspondence to any of the Requirement R1's. Without a definitive reference, the SDT is unable to respond to your comment. The new TOP-003-2, Requirement R1 addresses all time frames, including seasonal planning operations coordination.		
Platte River Power Authority Operations Group	No	Terms need to be defined and clarificaiton needs to be added.
Duke Energy	No	We believe that more clarity is needed on the requirements in these standards before going to ballot.
Response: The SDT has clarified requirements, defined terms and agrees that one more draft and posting is necessary.		
US Bureau of Reclamation	No	The two outstanding issues related to the new language proposed by the SDT need to be resolved first.TOP 001 needs to be modified to either recognize that the GOP can determine which operations can impact other reliability entities or insert a new requirement that the TOP must develop and provide to the GOP the operations that may impact other reliability entities.

Organization	Yes or No	Question 6 Comment
		TOP 003 needs to be modified to either place specific limitations on the data specifications developed by the TOP or that the Reliability Coordinator must approve data specification developed by the TOP when they are disputed by the reliability entity which must satisfy the obligations such data specifications impose on them.
Response: The SDT agrees that the Generator Operator will not know of operations on the BES and has deleted the requirement. The SDT has changes Part 1.3 and added Part 1.4 to address these concerns. Part 1.2 requires a mutually agreeable format. Requirement R4 requires the entities receiving the data specification to provide it in a format that they agreed upon which includes the timeframe.		
Independent Electricity System Operator	No	We continue to strongly disagree with removing the requirements for a TOP to plan and make day ahead arrangement for operating with all SOLs, and during day at hand and real time operate the system within established SOLs (and IROLs) and mitigate SOL exceedances within a predetermined time period. These are the most critical tasks for the TOPs, and are fundamental to ensuring reliability. We are unable to support these standards if the necessary requirements are not reinstated/revised (as suggested in Q1 to change R5 of TOP-001 and in Q2 to change R2 of TOP-002). Finally, we recommend changing “local” in R6 to “Transmission Operator” to avoid creating ambiguity regarding what is referred to in the requirement.
Response: The SDT has made numerous changes to TOP-001-2 and TOP-002-3 to include the concept of local reliability SOLs. In Requirement R6 (now Requirement R8) “local” was intended to clarify that these SOLs, while important, did not affect bulk power system reliability. The SDT continues to believe that the use of the word “local” conveys the intent better than the term “Transmission Operator” would.		
Northeast Power Coordinating Council	No	We continue to strongly disagree with removing the requirements for a TOP to plan and make day ahead arrangement for operating with all SOLs, and during day at hand and real time operate the system within established SOLs (and IROLs) and mitigate SOL exceedances within a predetermined time period. These are the most critical tasks for the TOPs, and are fundamental to ensuring reliability. We are unable to support these standards if the necessary requirements are not reinstated/revised (as suggested in Q1 to change R5 of TOP-001 and in Q2 to change R1 and R2 of TOP-002). R6 should be reworded to read "Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs)which, while not IROLs, support its Transmission Operator area reliability.
Response: The SDT has made numerous changes to TOP-001-2 and TOP-002-3 to include the concept of local reliability SOLs.		
Xcel Energy	No	We feel several modifications are needed before this is ready to ballot, as detailed in our previous responses. Also, the SDT indicates that changes in this project are dependent upon changes in Project 2006-06. Final drafts of those standards are not complete and it is not clear from a mapping perspective as to how some of the

Organization	Yes or No	Question 6 Comment
		requirements originally in TOP are now covered under those standards.
FirstEnergy	No	We feel that the current draft still has issues to be addressed before balloting begins (see our comments on Questions 1 through 5). Also, we provide the following additional comments:1. The mapping of all the requirements and standards associated with this project provided within the Implementation Plan during the first posting is a valuable tool for industry personnel in charge of tracking compliance. However, this mapping matrix now appears to be removed from the implementation plan. We feel that the team and/or NERC should provide a revised mapping document during the next posting of documents for this project so that industry can review it. Then it should be retained as a reference tool for industry when transitioning their compliance documentation from the current standards to the new standards. 2. The implementation plan currently states: "The assumption used by the SDT in establishing this Implementation Plan is that the project mentioned in the prerequisites: Project 2006-06, Reliability Coordination; has been approved prior to the implementation of this Project 2007-03, Real-Time Operations." It should be clear that the implementation clock for these Real-Time Operations standards starts only after "applicable regulatory approval" of the standards associated with Project 2006-06.
Response: The SDT agrees that one more posting is necessary. The mapping matrix, which clearly identifies the linkages to Project 2006-06, has undergone substantial revision and will be provided with the next posting. The current plan of the SDT for this project is to submit it for approval simultaneously with Project 2006-06, Reliability Coordination.		
James A Maenner	Yes	
Lakeland Electric	Yes	
Midwest ISO Standards Collaborators	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		