NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Draft 9 of the IROL Standards — IRO-008-1 through IRO-010-1

The IROL Standard Drafting Team thanks all commenters who submitted comments on draft 9 of the Interconnection Reliability Operating Limit standards. These standards were posted for a 30-day public comment period from March 26, 2008 through April 25, 2008. The stakeholders were asked to provide feedback on the SAR through a special Standard Comment Form. There were 15 sets of comments, including comments from more than 100 different people from more than 40 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders and FERC staff, and the drafting team's consideration of those comments, the drafting team made the following modifications to the standards:

IRO-008

- Added clarifying language to the definition of Operational Planning Analysis to clarify that the analysis may be performed a day ahead or as much as 12 months ahead of real-time.
- Added clarifying language to the VSLs for R2 to identify that the VSLs are based on the review of a specific sample size.

IRO-009

- The drafting team removed 4.2 from the Applicability Section (limited applicability to the IROLs associated with contingencies identified in FAC-010 and FAC-014) of the standard because it duplicated information already included in the requirements.
- Modified R1 – R5 and associated measures and VSLs to clarify that the action plans and actions in this standard are limited to those associated with IROLs in the Reliability Coordinator's own Reliability Coordinator Area. IRO-016 addresses coordination when there is an IROL in another Reliability Coordinator's Area, or when there is a need to coordinate development and execution of action plans involving more than one Reliability Coordinator.
- Added a parenthetical phrase to R3 to clarify that the Reliability Coordinator may use any action plan at its disposal to prevent or mitigate an instance of exceeding an IROL
- Added a parenthetical phrase to R5 to clarify that "the most conservative value" is the value that has the least impact on reliability.
- Eliminated the "high" VSL for R3 in support of stakeholder comments indicating that the requirement is aimed at actions, not at preventing an instance of exceeding an IROL.
- Eliminated one of the two "severe" VSLs for R5 in support of stakeholder comments indicating that the two VSLs were redundant.

IRO-010

- Modified R1 and R1.1 in support of comments from FERC staff and stakeholders by adding words from the purpose and from R3 to clarify the intent of the requirement is to collect data and information needed by the Reliability Coordinator to support

Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments to prevent instability, uncontrolled separation, and cascading outages.

- Added a data retention period for R3 based on stakeholder comments. The data retention period added matches the period recommended by the Compliance Program.

- Revised the VSLs for R1 by reversing the VSLs for “Lower” and “Moderate” based on stakeholder comments indicating that missing the “mutually agreeable format” was less severe than missing the process for data provision when automated Real-Time system operating data is unavailable.

Implementation Plan:

- Removed the recommendation to retire Attachment 1 in TOP-005-2 because stakeholders identified that the attachment is still needed to support Requirement R3 in TOP-005-2.

Definition of Operational Planning Analysis

- Added language to clarify that the Operational Planning Analysis can be performed a day ahead or as much as 12 months ahead.

The drafting team believes that the above modifications will satisfy most comments suggesting that the standards or implementation plan need adjustments. There were several places where stakeholders indicated a lack of understanding in the terminology associated with some of the defined terms as well as confusion about some of the terminology associated with the elements in the standard used by the compliance program such as time horizons and violation risk factors. The drafting team believes that the information it provided should satisfy these commenters.

The drafting team did not adopt the following proposed modifications from stakeholders or from FERC staff:

- Some commenters who agreed that monitoring is a supporting activity, indicated a concern that removing the monitoring requirement may impact other requirements in other standards that rely upon monitoring. The drafting team did not return the monitoring requirements to the standards. Entities that do not have real-time system operators actively monitoring the status of the bulk power system cannot achieve the performance-related requirements in this standard and in other standards.

- Some commenters wanted the Severe VSL for failing to resolve an IROL within the IROL’s T_v to be a “High” VSL when the Reliability Coordinator took action to resolve the IROL but was not successful. The drafting team believes that this change would violate the guidelines for setting VSLs. The intent of the requirement is not met at all if the IROL is not resolved within the IROL T_v. The guidelines for setting VSLs indicate that if the intent of the requirement is mostly or totally unmet, then the VSL should be “Severe.”

- FERC staff interpreted one of the directives in Order 693 as requiring the Reliability Coordinator to have action plans to implement if a contingency occurs during the system adjustment period following an instance of exceeding an IROL, but before the IROL T_v has been reached and before the system has been returned to a stable state. The drafting team did not interpret the directive (paragraph 1601 of Order 693) in this manner. The IROL standards require an action plan for all IROLs identified a day or more ahead of the current day for all IROLs within the Reliability Coordinator’s Reliability Coordinator Area. The drafting team does not think it is practical to develop action plans for all possible contingencies that could occur during the adjustment period while the system is being returned to a stable state.

- There were several commenters who indicated the VRFs for requirements associated with having action plans should be modified from “Medium” to “High.” The drafting team had posted the VRFs for comment in an earlier posting, and the same commenters had earlier agreed that the VRFs should be “Medium.” Because the drafting team had achieved what appeared to be consensus on the VRFs in the earlier posting, the drafting team did not make the requested change. Failure to have an action plan should not, by itself, cause or contribute to uncontrolled separation, instability, or cascading.

The drafting team does not believe that the modifications made are significant enough to warrant posting the revised standards for an additional comment period, and will ask the Standards Committee for authorization to move the standards and the implementation plan forward to ballot.

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

http://www.nerc.com/~filez/standards/IROL.html

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

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

Index to Commenters, Questions, Comments, and Responses

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<tr><td>3.</td><td>William DeVries</td><td>New York Independent System Operator</td><td>NPCC</td><td>2</td></tr>
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<tr><td>13.</td><td>Sylvain Clermont</td><td>Hydro-Quebec TransEnergie</td><td>NPCC</td><td>1</td></tr>
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<tr><td>5.</td><td>Kyle McMenamin</td><td>Southwestern Public Service</td><td>SPP</td><td>1, 3, 5</td></tr>
<tr><td>6.</td><td>Robert Rhodes</td><td>Southwest Power Pool</td><td>SPP</td><td>2</td></tr>
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<tr><td>Group</td><td>Melinda Montgomery</td><td>SERC OC Standards Review Group - IROL Standards, IRO-008-1, 009-1, 010-1</td><td>1 - Transmission Owners, 3 - Load-serving Entities</td><td>
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<tr><td>3.</td><td>Stuart Goza</td><td>Central Sub-region Reliability Coordinator (TVA)</td><td>SERC</td><td>1, 3, 9</td></tr>
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<tr><td>9.</td><td>Danny Dees</td><td>Municipal Electric Authority of GA</td><td>SERC</td><td>1, 3</td></tr>
<tr><td>10.</td><td>Steve Corbin</td><td>Southeastern Sub-region Reliability Coordinator (Southern Company)</td><td>SERC</td><td>1, 3</td></tr>
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<tr><td>14.</td><td>George Carruba</td><td>East Kentucky Power Cooperative</td><td>SERC</td><td>1, 3, 5</td></tr>
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<tr><td>Individual</td><td>Randy Schimka</td><td>San Diego Gas and Electric Co.</td><td>5 - Electric Generators, 3 - Load-serving Entities, 1 - Transmission Owners</td><td></td></tr>
<tr><td>Individual</td><td>Ron Falsetti</td><td>Ontario IESO</td><td>2 - RTOs and ISOs</td><td></td></tr>
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<tr><td>2. Jim Castle</td><td>NYISO</td><td>NPCC</td><td>2</td></tr>
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<tr><td>Group</td><td>Doug Hohlbaugh</td><td>FirstEnergy</td><td>3 - Load-serving Entities, 5 - Electric Generators, 6 - Electricity Brokers, Aggregators , 1 - Transmission Owners</td><td><table>
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<tr><td>2.</td><td>John Wenrich</td><td>FE</td><td>RFC</td></tr>
<tr><td>3.</td><td>John Reed</td><td>FE</td><td>RFC</td></tr>
<tr><td>4.</td><td>Dick Kovacs</td><td>FE</td><td>RFC</td></tr>
<tr><td>5.</td><td>Dave Folk</td><td>FE</td><td>RFC</td></tr>
<tr><td>6.</td><td>Sam Ciccone</td><td>FE</td><td>RFC</td></tr>
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<tr><td>Individual</td><td>Alessia Dawes</td><td>Hydro One Networks</td><td>3 - Load-serving Entities, 1 - Transmission Owners</td><td></td></tr>
<tr><td>Individual</td><td>Kathleen Goodman</td><td>ISO New England Inc</td><td>2 - RTOs and ISOs</td><td></td></tr>
<tr><td>Individual</td><td>Jason Shaver</td><td>American Transmission Company LLC</td><td>1 - Transmission Owners</td><td></td></tr>
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1. The drafting team eliminated IRO-007-1 Requirement R1, the requirement for the Reliability Coordinator to "monitor" its wide area. Monitoring is a "how" – staying within the IROLs is the "required performance." Do you agree with this change?

Summary Consideration: Most stakeholders who responded to this question agreed with the removal of Requirement R1 from IRO-007-1.

Organization/Group		Question 1 Comments:
Ontario IESO	No	The IESO agrees that monitoring is implicit in this set of standards given the RC is held responsible for operating the system within IROLs, and taking corrective actions to prevent and mitigate instances where an SOL or IROL is (or expected to be) exceeded. Nonetheless, the requirement to monitor drives the need for other standards, such as communication and provision of monitoring facilities. Its removal may leave a void in this aspect. We suggest the Standard Drafting Team consider the impact of removing this requirement on the other standards.
Response: The drafting team has considered the impact of removing this requirement. Other drafting teams (Reliability-based Control SDT, Reliability Coordination SDT, and Real-time Operations SDT) have removed the "monitoring" requirements from other standards for the same reason that the IROL SDT proposed removing this monitoring requirement. Monitoring is a supporting task used to achieve the objective of operating within IROLs. Most stakeholders who provided comments support the drafting team's position. FERC has said, if you have a plan, by definition you have to implement it – this is a parallel argument – if you must operate within IROLs, you must monitor.		
ISO RTO Council Standards Review Committee	No	On the one hand, the IRC agrees that monitoring is implicit in this set of standards given the RC is held responsible for operating the system within IROLs, and taking corrective actions to prevent and mitigate instances where an SOL or IROL is (or expected to be) exceeded. Nonetheless, the requirement to monitor drives the need for other standards, such as communication and provision of monitoring facilities. Its removal may leave a void in this aspect. We are therefore unable to indicate a preference. We suggest the Standard Drafting Team consider the impact of removing this requirement on other standards.
Response: The drafting team has considered the impact of removing this requirement. Other drafting teams (Reliability-based Control SDT, Reliability Coordination SDT, and Real-time Operations SDT) have removed the "monitoring" requirements from other standards for the same reason that the IROL SDT proposed removing this monitoring requirement. Monitoring is a supporting task used to achieve the objective of operating within IROLs. Most stakeholders who provided comments support the drafting team's position. FERC has said, if you have a plan, by definition you have to implement it – this is a parallel argument – if you must operate within IROLs, you must monitor.		
ISO New England Inc	No	We understand that monitoring is implicit in this set of standards given the RC is held responsible for operating the system within IROLs, and taking corrective actions to prevent and mitigate instances where an SOL or IROL is (or expected to be) exceeded. Nonetheless, the requirement to monitor drives the need for other standards, such as communication and provision of monitoring facilities. Its removal may leave a void in this aspect. We suggest the SDT consider the ramifications of removing this requirement on other standards.
Response: Response: The drafting team has considered the impact of removing this requirement. Other drafting teams (Reliability-based Control SDT, Reliability Coordination SDT, and Real-time Operations SDT) have removed the "monitoring" requirements from other standards for the same reason that the IROL SDT proposed removing this monitoring requirement. Monitoring is a supporting task used to achieve the		

Organization/Group		Question 1 Comments:
objective of operating within IROLs. Most stakeholders who provided comments support the drafting team's position. FERC has said, if you have a plan, by definition you have to implement it – this is a parallel argument – if you must operate within IROLs, you must monitor.		
Hydro One Networks	Yes	We believe it is ok to eliminate IRO-007-1 R1, as IRO-008-1 R2 requiring the RC to perform "Real-Time Assessments" (every 30 minutes) to determine if any IROL is exceeded, covers off the intent of IRO-007-1 R1. In addition, IRO-008-1 R2 has, at a minimum, a Violation Risk Factor and Time Horizon at least equal to or stricter than IRO-007-1 R1.
Response: The drafting team appreciates your support. This is the philosophy the drafting team used in making the recommendation to retire the requirement.		
American Transmission Company LLC	Yes	ATC is okay with dropping IRO-007 R1 because it is covered in IRO-002-1 R5 and R6. IRO-002-1 R5 and R6 require the RC to monitor BES elements that could result in SOL or IROL violations.
Response: Thank you for your support. We advise you to monitor the work of the Reliability Coordination standard drafting team as they are recommending retirement of IRO-002-1 R5 and R6.		
Northeast Utilities	Yes	
NPCC Regional Standards Committee, RSC	Yes	
Hydro-Québec TransEnergie	Yes	
Entergy Services	Yes	
Manitoba Hydro	Yes	
Operating Reliability Working Group	Yes	
SERC OC Standards Review Group - IROL Standards, IRO-008-1, 009-1, 010-1	Yes	
San Diego Gas and Electric Co.	Yes	
FirstEnergy	Yes	

2. The drafting team moved IRO-007-1 Requirement R2 (from IRO-007 R2 to IRO-009 R5), the requirement for the Reliability Coordinator to use the most conservative value under consideration when there is a disagreement amongst Reliability Coordinators on the value of an IROL or its T_v. This move seemed to put the related requirements together in a single standard and allowed the elimination of IRO-007. Do you agree with this change?

Summary Consideration: All commenters who responded to this question agreed with moving Requirement R2 from IRO-007-1 to IRO-009.

Organization/Group		Question 2 Comments:
Northeast Utilities	Yes	Please define Tv in the standard.
Response: IROL Tv is an approved definition.		
Hydro One Networks	Yes	Since IRO-007-1 R2 describes an action with respect to IROLs, it is appropriate to move that requirement to the IRO-009-1 standard Reliability Coordinator Actions to Operate within IROLs. In addition, the VRF, Time Horizon and VSL (severe) have all been kept the same. Therefore elimination of IRO-007-1 is also appropriate at this time.
Response: The drafting team appreciates your support.		
NPCC Regional Standards Committee, RSC	Yes	
Hydro-Québec TransEnergie	Yes	
Entergy Services	Yes	
RCCWG - reliability coordinator comments working group	Yes	
Manitoba Hydro	Yes	
Operating Reliability Working Group	Yes	
SERC OC Standards Review Group - IROL Standards, IRO-008-1, 009-1, 010-1	Yes	
San Diego Gas and Electric Co.	Yes	
Ontario IESO	Yes	
ISO RTO Council Standards Review Committee	Yes	
FirstEnergy	Yes	
ISO New England Inc	Yes	
American Transmission Company LLC	Yes	

3. The drafting team modified the Violation Severity Levels for IRO-008. Do you agree with the new VSLs?

Summary Consideration: None of the commenters who responded to this comment indicated agreement with the proposed VSLs. Some comments indicated misunderstanding of the definition of "Real-time Assessment," some commenters indicated confusion about the multiple definitions being used for the term, "Time Horizons," and some commenters asked for more clarity in the use of "sample periods" in the VSLs for R1 and R2.

Real-time Assessments – Some commenters suggested that the VSLs in R2 are overly punitive, because they don't allow any "down time" for the EMS. The term, "Real-time Assessment" is defined as follows and does not have to be performed using only a state estimator – the definition allows the use of other tools and processes:

– An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.

The definition was designed so that you could still conduct a Real-time Assessment, if needed, using readily available data collected through manual processes.

Time Horizons - The "Time Horizons" used for the Sanctions Guidelines are not the same as the operations and planning periods described in the Functional Model. The *Glossary of Terms Used in Reliability Standards* does not include an approved definition of either the term "Planning Horizon" – or the term, "Operations Horizon." The Time Horizons (designed for use in determining the size of a penalty or sanction) associated with each requirement in a standard use the following definitions:

– Long-term Planning — a planning horizon of one year or longer.
– Operations Planning — operating and resource plans from day-ahead up to and including seasonal.
– Same-day Operations — routine actions required within the timeframe of a day, but not real-time.
– Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system.
– Operations Assessment — follow-up evaluations and reporting of real time operations.

Sample Periods - Commenters asked the drafting team to identify the basis for the VSLs for R1, in particular the 30-day "sample" period. Commenters also asked the drafting team to identify the basis for the use of the 24 hour period for the VSLs for R2 and suggested that there was a conflict with a VSL that described noncompliant performance measured over a 30 day period with the definition of Operational Planning Analysis. These comments indicate a misunderstanding on the use of VSLs as well as a misunderstanding about the definition of "Operational Planning Analysis." VSLs describe categories of noncompliant performance and are used by the Compliance Enforcement Authority to help determine the size of a penalty or sanction. The VSLs for R1 are based on the Compliance Enforcement Authority using the data retained by the responsible entity to determine if there were noncompliant performance. The Data Retention period for evidence used to show compliance with Requirement R1 is a rolling 30 days. If, after reviewing the 30 days of data, the Compliance Enforcement Authority finds that there were three days that did not have an operational planning analysis, then the noncompliant performance falls into the High Violation Severity Level category. Based on the comments, the drafting team modified the VSLs for R2 to provide clarity by making the following addition to each of the VSLs for R2:

Lower VSL for R2: For any sample 24 hour period within the 30 day retention period, a ~~A~~ Real-time Assessment was not conducted for one 30-minute period within ~~a~~ that 24-hour period

The drafting team added a sentence to the definition of "Operational Planning Analysis" as shown below to clarify that the analysis is for the next day's operation – but the analysis does not necessarily have to be conducted every day.

Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (The analysis may be performed either a day ahead or as much as ~~and up to~~ 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Organization/Group		Question 3 Comments:
Ontario IESO	No	We agree with the changes to the VSLs for R2 and R3, but are unable to identify the basis for the VSLs for R1, in particular the 30-day "sample" period. This question also applies to the 24 hour period for the VSLs for R3 except in the context of real-time operation, most would assume the next 24 hours being a part of the real-time horizon. The 30-day period, however, may not be generalized for the operational planning horizon given a 12 month period already specified in the definition for Operational Planning Analysis. We asked the SDT to extend the sampling period to 12 months in accordance with the general understanding of the time frame for operations planning.

Response: The 30 days in the VSLs for R1 came from the data retention period for R1 in this standard – which is a rolling 30 days for R1. The data retention period was intended to ensure that there is sufficient data for the Compliance Enforcement Authority to measure compliance, without overwhelming the responsible entity. We do not agree that RCs should retain 12 rolling months of analyses to demonstrate compliance with this requirement since it would be burdensome to retain that much data.

The drafting team assumes that the comment about R3 is really about R2 – since the VSL for R2 includes the "24 hour period" and R3's VSLs do not. The intent of the 24 hour period was to set boundaries on the sample size used to assess compliance. The drafting team modified the VSL to include language to identify that the VSLs are based on a sample 24 hour period within the 30 day retention period.

The "Time Horizons" used for the Sanctions Guidelines are not the same as the operations and planning periods described in the Functional Model. The Time Horizons associated with each requirement in the standard, use the following definitions of the various time periods:

– Long-term Planning — a planning horizon of one year or longer.
– Operations Planning — operating and resource plans from day-ahead up to and including seasonal.
– Same-day Operations — routine actions required within the timeframe of a day, but not real-time.

– Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system. – Operations Assessment — follow-up evaluations and reporting of real time operations. Note that the Glossary of Terms Used in Reliability Standards does not include an approved definition of either the "Planning Horizon" – or the term, "Operations Horizon."		
Northeast Utilities	No	We agree with the changes to the VSLs for R2 and R3, but are unable to identify the basis for the VSLs for R1, in particular the 30-day "sample" period. This also applies to the 24 hour period for the VSLs for R3 except in the context of real-time operation, most would assume the next 24 hours being a part of the real-time horizon. The 30-day period, however, may not be generalized for the operational planning horizon given a 12 month period already specified in the definition for Operational Planning Analysis.
Response: Please see the Summary Consideration and the response to IESO.		
NPCC Regional Standards Committee, RSC	No	We agree with the changes to the VSLs for R2 and R3, but are unable to identify the basis for the VSLs for R1, in particular the 30-day "sample" period. This also applies to the 24 hour period for the VSLs for R3 except in the context of real-time operation, most would assume the next 24 hours being a part of the real-time horizon. The 30-day period, however, may not be generalized for the operational planning horizon given a 12 month period already specified in the definition for Operational Planning Analysis.
Response: Please see the Summary Consideration and the response to IESO.		
Hydro-Québec TransEnergie	No	HQT agree with the changes to the VSLs for R2 and R3, but is unable to identify the basis for the VSLs for R1, in particular the 30-day "sample" period. This also applies to the 24 hour period for the VSLs for R3 except in the context of real-time operation, most would assume the next 24 hours being a part of the real-time horizon. The 30-day period, however, may not be generalized for the operational planning horizon given a 12 month period already specified in the definition for Operational Planning Analysis.
Response: Please see the Summary Consideration and the response to IESO.		
ISO New England Inc	No	We agree with the changes to the VSLs for R2 and R3, but are unable to identify the basis for the VSLs for R1, in particular the 30-day "sample" period. This question also applies to the 24 hour period for the VSLs for R3 except in the context of real-time operation, most would assume the next 24 hours as being the real-time horizon. The 30-day period, however, may not be generalized for the operational planning horizon given a 12 month period already specified in the definition for Operational Planning Analysis. We ask the SDT to extend the sampling period to 12 months in accordance with the general understanding of the time frame for operations planning.
Response: Please see the Summary Consideration and the response to IESO.		
ISO RTO Council Standards Review Committee	No	We agree with the changes to the VSLs for R2 and R3, but are unable to identify the basis for the VSLs for R1, in particular the 30-day "sample" period. This question also applies to the 24 hour period for the VSLs for R3 except in the context of real-time operation, most would assume the next 24 hours being a part of the real-time horizon. The 30-day period, however, may not be generalized for the operational planning horizon given a 12 month period already specified in the definition for Operational Planning Analysis. We ask the SDT to extend the sampling period to 12 months in accordance with the general understanding of the time frame for operations planning.
Response: Please see the Summary Consideration and the response to IESO.		
SERC OC Standards	No	We feel that the Violation Severity Levels for IRO-008-1, R2, if applied as currently proposed, are unduly restrictive in

Review Group - IROL Standards, IRO-008-1, 009-1, 010-1		measuring the impact of violating the requirement to run a real-time assessment every thirty (30) minutes for the following reasons: 1. During a large portion of the time, system conditions do not change within a thirty (30) minute period and the risk to the interconnection is not the same for every thirty (30) minute period. When violations are not commensurate with the risk to the Interconnection or where there is no real harm, the penalties should be waived or reduced accordingly. Another way of saying this is that the Violation Severity Level and measurement criteria of IRO-008-1 do not measure the potential risk to the interconnection due to violation of these criteria. In fact, no strictly time based criteria can. The best criteria would be the determination of risk to the interconnection (or change in the level of risk in a positive or higher risk direction) that was not properly detected and acted upon by the Reliability Coordinator. One potential way that this could actually be measured during "after the fact audits" is by choosing a set of specific occurrences during the previous year that impacted interconnection reliability within the RC area and reviewing the RC's documented responses to them. This would greatly enhance the ability of auditors to measure actual RC performance rather than just measuring how often the RC went through the motions of performing an analysis. 2. The requirements do not allow for scheduled maintenance or unplanned down time of EMS systems, thereby requiring a perfect compliance performance for 17,520 study periods in a year. This doesn't allow for any down time for EMS or assessment applications (State Estimator) and this imposes impossible criteria on EMS operations and guarantees that every system will have one or more violations each year. This places an emphasis on or actually measures the performance of tools rather than on the performance of the Reliability Coordinators 3. The drafting team may want to seriously reconsider the thirty (30) minute requirement for running real time assessments. Hourly assessments would be more practical for assessing system conditions and for compliance requirements. Systems generally conduct continuous assessments during peak load or abnormal conditions and Reliability Coordinators and Operators should be allowed the flexibility to make reasoned judgments based on their knowledge of the system during normal conditions or during failures of assessment tools. Our support for an hourly interval is also based upon the recommendations of the NERC Real-time Tools Best Practices Task Force. On pages 156-158 of section 2 of their report, the RTBPTF proposes that a new requirement for "look-ahead analyses" be added to standards TOP-002 and IRO-004. Since IRO-008 is intended to replace IRO-004, the recommendation is applicable to IRO-008. Specifically, the recommendation as it pertains to RCs is paraphrased as follows: In order to assess approaching IROL violations, each Reliability Coordinator shall, at a minimum, perform one-hour-ahead Power Flow simulations during the following: + Occurrence of critical system event + Extreme load conditions + Large power transactions + Major planned outages. This recommended requirement would address the "expected" system conditions component of the proposed (and so-called) "Real Time" Assessment. The "existing" system conditions component should be covered by requirements for monitoring found elsewhere in the standards. The rationale for the RTBPTF recommendation came from a deficiency identified in the Blackout Report. Specifically, the report stated: "FE did not perform adequate hour-ahead operations planning studies after Eastlake 5 tripped off-line at 13:31 to ensure that FE could maintain a 30-minute

		response capability for the next contingency. The FE system was not within single contingency limits from 15:06 to 16:06. In addition to day-ahead planning, the system should have been restudied after the forced outage of Eastlake 5."The recommendation is supported by the findings of the RTBPTF based upon responses received from the task force's survey of RCs and TOPs. The survey showed that 47% of all respondents performed look-ahead studies at intervals less than one hour, and 80% perform such studies at intervals from one hour to one day. Also, 83% of the respondents perform these studies as needed. The survey results indicate that performing look-ahead studies when needed on at least an hourly basis is a prevailing practice. We suggest that the Standards Drafting Team work with the RTBPTF to incorporate their recommendation into IRO-008 in lieu of the proposed requirement R2.) We are also concerned about the requirements for evidence to validate compliance with the IRO-008-1 Standard as well as other standards. The compliance program seems to define the window of compliance being the 3 years between compliance audits. However, the IRO-008-1 standard only requires data be retained to demonstrate compliance for a rolling 30 day period. There appears to be a disconnect between the compliance program and the standard, which exposes the Reliability Coordinators to being found non-compliant In other words, there appears to be a considerable window of time between an audit and the previous audit during which an entity would not have data to demonstrate that they met compliance expectations.] In many cases, the data retention sections in individual standards talk about a much shorter data retention expectation. For example, IRO-008-1 states, ?The Reliability Coordinator shall retain evidence for Requirement R1, Measure M1 and Requirement R2, Measure M2 for a rolling 30 days. The Reliability Coordinator shall keep evidence for Requirement R3, Measure M3 for a rolling three months. The question is which data retention expectation is the entity going to be held to with regards to compliance and compliance audits? More clarity needs to be provided on what evidence must be provided in audits.

Response:

1. VSLs are not used to "measure" performance – they are used to categorize the different types of noncompliant performance that might be found. VSLs are intended to provide up to four different descriptions of varying degrees of noncompliant performance – with the lower VSL describing noncompliant performance that is close to fully compliant – and the severe VSL describing noncompliant performance where the performance measured is so far away from being compliant that either the performance is totally noncompliant or the performance is so non-compliant that the intent of the requirement has not been met at all. VSLs are not used to assess the reliability-related risk of the noncompliant performance. The drafting team disagrees that it is acceptable to only apply a penalty when there has been an incident or event. Standards should promote good performance that results in a reliable system – ignoring poor performance because nothing evil occurred to the system due to "luck" is not a concept supported for something as critical as looking at the system to see if an IROL has been exceeded.

2. R1 and R2 – The requirements do not prescribe the use of any specific tools. If you don't have access to the EMS, you still have to do the Operational Planning Analysis and the Real-time Assessments – you can use engineering judgment in coordination with previous analyses and the latest available information, if needed.

3. The "30 minutes" was selected as the threshold because when an IROL has been exceeded, the Reliability Coordinator must return the system to within the IROL in the IROL's T_v – and the IROL's T_v cannot exceed 30 minutes.

4. Monitoring is a "how" not a reliability requirement that, by itself, results in a measurable performance. The drafting team has removed the

monitoring requirements with the support of most stakeholders. R2 is intended to assure that entities perform assessments at regular intervals, and the drafting team selected 30 minutes because IROLs have to be resolved within their Tv – and Tv cannot be longer than 30 minutes. The RTBPTF did not provide any comments in response to the posting of this set of standards. The drafting team followed up with one of the commenters to more fully understand the above comments. The concern was really with the idea that R2 would require a mitigation plan for Real-time Assessments. It seems that the commenters did not see the definition of “Real-time Assessments”. 5. Requirements in standards are not designed to support “common practices” – they are designed to support what is needed for reliability. R2 is intended to assure that entities perform assessments at regular intervals, and the drafting team selected 30 minutes (with stakeholder support) because IROLs have to be resolved within their T_v – and T_v cannot be longer than 30 minutes. The ERO Rules of Procedure Appendix 4C specify that the data retention period in the standard supersedes retaining data for the current year and all years since the last audit. See Appendix 4C Section 3.1.4 which states: 3.1.4 Scope of Compliance Audits A Compliance Audit will include all Reliability Standards applicable to the Registered Entity monitored in the NERC Implementation Plans in the current and three previous years, and may include other Reliability Standards applicable to the Registered Entity. If a Reliability Standard does not require retention of data for the full period of the Compliance Audit, the Compliance Audit will be applicable to the data retention period specified in the Reliability Standard.		
RC WG - reliability coordinator comments working group	No	R2 - does this real time assessment only mean state estimator or if state estimator is unavailable, can the RC use other tools to make a real time assessment to meet this requirement? If we can not use other tools then we do not agree with the VSL. If we can use other tools, then we agree with the VSL.
Response: The term, “Real-time Assessment” is defined as follows and does not have to be performed using only a state estimator – the definition allows the use of other tools and processes: An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data. The definition was designed so that you could still conduct a real-time assessment, if needed, using readily available data collected through manual processes.		
Operating Reliability Working Group	No	As proposed the VSLs do not allow any Real-time Assessments to be missed within a 24-hour period. However, in EOP-008-0, R1.8, the Reliability Coordinator is allowed a one-hour transition period to its backup site. It would seem appropriate that an allowance should be made for this transition in the VSLs for R2.
Response: The real-time assessment can be conducted using manual data collection, if needed. The Reliability Coordinator is responsible for having processes in place that assure it can meet all its real-time requirements, even while in transition from its primary control facility. For example, responsibility for conducting the real-time assessments can be delegated to the Reliability Coordinator’s Transmission Operators. There is a drafting team working on revisions to EOP-008.		
Hydro One Networks	No	For VSL requirement R1 we suggest the following: High: Missed performing an Operational Planning Analysis that covers all aspects of the requirement for one of 30 days; Severe: Missed performing an Operational Planning Analysis

		that covers all aspects of the requirement for two or more of 30 days. As well, for VSL requirement R2 we suggest changing the phrase "within a 24-hour period" to "within a 30-day period". This will prevent daily occurrences of violations.
Response: The proposed change would not prevent daily occurrences of violations. If an entity misses doing an Operational Planning Analysis, the responsible entity must self-report the violation. If the entity missed doing the Operational Planning Analysis for three days, then the entity would need to self-report the violation. The 30 days in the VSLs for R1 came from the data retention period for R1 in this standard – which is a rolling 30 days for R1. The data retention period was intended to ensure that there is sufficient data for the Compliance Enforcement Authority to measure compliance, without overwhelming the responsible entity. We do not agree that Reliability Coordinators should retain 12 rolling months of analyses to demonstrate compliance with this requirement since it would be burdensome to retain that much data. The proposed change also provides fewer variants of noncompliant performance – and limits the amount of "partial credit" an entity can be granted for attempting to meet compliance. Please see the revised VSLs for R2 – the drafting team added some language to clarify that the intent was to add boundaries to the amount of data that the compliance enforcement authority will review when determining compliance to support consistency.		
FirstEnergy	Yes	You may want to remove the parenthetical reference to the requirement numbers at the end of each VSL. This is not needed since the requirement number is shown in the VSL table in column 1.
Response: The drafting team left the reference numbers in at the request of NERC staff. The standards will be added to a relational database and the reference numbers will be useful.		
Manitoba Hydro	Yes	
American Transmission Company LLC	Yes	
San Diego Gas and Electric Co.	Yes	
Entergy Services	Yes	

4. The drafting team modified IRO-009-1 R1 and R2 by replacing the phrase, "in advance of real-time" with the phrase, "one or more days prior to the current day" to clarify the intent and measurability of these requirements. Do you agree with the change made to R1 and R2 in IRO-009-1?

Summary Consideration: Most commenters, except for those from within the NPCC Region agreed with the change. The commenters from the NPCC Region who disagreed with the change felt that the change may result in arguments over the phrase, "in advance of real-time," and suggested that real time is 'understood' to be the current hour. The drafting team disagrees – the term, "real-time" is a defined term and its definition is, "Present time as opposed to future time," which is significantly different from the "current hour." These commenters suggested that the Reliability Coordinator have an action plan for all IROLs identified "one or more hours ahead of real time" or "beyond the current hour." Because the requirements in the standard are intended to work cooperatively with the requirements to conduct Operational Analyses and Real-time Assessments, the proposed revision wasn't adopted. The Operational Planning Assessment is looking at least at the day ahead – and the Real-time Assessment is looking at the actual system conditions – the proposed change would require adding a requirement for the Reliability Coordinator to conduct Operational Planning Assessments throughout the day for a look ahead at the remainder of today's operation and isn't practical.

The Reliability Coordinator has a responsibility to oversee the reliability of its Reliability Coordinator Area, and take what ever actions necessary to protect the reliability of the interconnection. The drafting team does not believe that the standard needs to tell the Reliability Coordinator to conduct additional studies and develop additional plans if the actual conditions do not match the studied conditions. It isn't possible to have a plan for every possible instance of exceeding an IROL.

Organization/Group		Question 4 Comments:
Northeast Utilities	No	We understand that this change is to address possible arguments over what "in advance of real time" really means. However, this change may result in another argument over the coverage of the time period "beyond next hour to the rest of the current day". And with this change, one could interpret that the RC does not need to prepare for action plans for those IROLs not identified in "real-time" or beyond current day. This may leave a hole in reliable operations. To fill this potential "hole", we suggest the "in advance of real time" be replaced with "one or more hours prior to real time", which the real time being understood, or defined, to be current hour. Alternatively, the phrase could be replaced with "beyond the current hour".
Response: The proposed modification was not adopted. The intent of this requirement is to ensure that, in real-time and the day ahead, the Reliability Coordinator is prepared to take whatever actions necessary, to prevent and/or mitigate instances of violating IROLs. There is no hole in the reliability process because if the Operational Planning Analysis does not project the potential IROL violation, then at a minimum, the next Real-time Assessment will detect it. It isn't possible to have a plan for every possible instance of exceeding an IROL. The term, 'real-time' is defined as follows in the NERC Glossary of Terms Used in Reliability Standards: Present time as opposed to future time. Thus, we cannot make an assumption that "real-time" means the current hour.		

NPCC Regional Standards Committee, RSC	No	We understand that this change is to address possible arguments over what "in advance of real time" really means. However, this change may result in another argument over the coverage of the time period "beyond next hour to the rest of the current day". And with this change, one could interpret that the RC does not need to prepare for action plans for those IROLs not identified in "real-time" or beyond current day. This may leave a hole in reliable operations. To fill this potential "hole", we suggest the "in advance of real time" be replaced with "one or more hours prior to real time", which the real time being understood, or defined, to be current hour. Alternatively, the phrase could be replaced with "beyond the current hour".
Response: The proposed modification was not adopted. The intent of this requirement is to ensure that, in real-time and the day ahead, the Reliability Coordinator is prepared to take whatever actions necessary, to prevent and/or mitigate instances of violating IROLs. There is no hole in the reliability process because if the Operational Planning Analysis does not project the potential IROL violation, then at a minimum, the next Real-time Assessment will detect it. It isn't possible to have a plan for every possible instance of exceeding an IROL. The term, 'real-time' is defined as follows in the NERC Glossary of Terms Used in Reliability Standards: Present time as opposed to future time. Thus, we cannot make an assumption that "real-time" means the current hour.		
Ontario IESO	No	We understand that this change is to address possible arguments over what "in advance of real time" really means. However, this change may result in another argument over the coverage of the time period "beyond next hour to the rest of the current day". And with this change, one could interpret that the RC does not need to prepare for action plans for those IROLs not identified in "real-time" or beyond current day. This may leave a hole in reliable operations. To fill this potential "hole", we suggest the "in advance of real time" be replaced with "one or more hour prior to real time", which the real time being understood, or defined, to be current hour. Alternatively, the phrase could be replaced with "beyond the current hour".
Response: The proposed modification was not adopted. The intent of this requirement is to ensure that, in real-time and the day ahead, the Reliability Coordinator is prepared to take whatever actions necessary, to prevent and/or mitigate instances of violating IROLs. There is no hole in the reliability process because if the Operational Planning Analysis does not project the potential IROL violation, then at a minimum, the next Real-time Assessment will detect it. It isn't possible to have a plan for every possible instance of exceeding an IROL. The term, 'real-time' is defined as follows in the NERC Glossary of Terms Used in Reliability Standards: Present time as opposed to future time. Thus, we cannot make an assumption that "real-time" means the current hour.		
ISO RTO Council Standards Review Committee	No	We understand that this change is to address possible arguments over what "in advance of real time" really means. However, this change may result in another argument over the coverage of the time period "beyond next hour to the rest of the current day". And with this change, one could interpret that the RC does not need to prepare for action plans for those IROLs not identified in "real-time" or beyond current day. This may leave a hole in reliable operations. To fill this potential "hole", we suggest the "in advance of real time" be replaced with "one or more hours prior to real time", with the real time being understood, or defined, to be current hour. Alternatively, the phrase could be replaced with "beyond the current hour".
Response: The proposed modification was not adopted. The intent of this requirement is to ensure that, in real-time and the day ahead, the Reliability Coordinator is prepared to take whatever actions necessary, to prevent and/or mitigate instances of violating IROLs. There is no hole in the reliability process because if the Operational Planning Analysis does not project the potential IROL violation, then at a		

minimum, the next Real-time Assessment will detect it. It isn't possible to have a plan for every possible instance of exceeding an IROL. The term, 'real-time' is defined as follows in the NERC Glossary of Terms Used in Reliability Standards: Present time as opposed to future time. Thus, we cannot make an assumption that "real-time" means the current hour. Earlier detection of a potential IROL violation could result in a more economic solution, but that is not a reliability issue		
Hydro-Québec TransEnergie	No	HQT understand that this change is to address possible arguments over what "in advance of real time" really means. However, this change may result in another argument over the coverage of the time period "beyond next hour to the rest of the current day". And with this change, one could interpret that the RC does not need to prepare for action plans for those IROLs not identified in "real-time" or beyond current day. This may leave a hole in reliable operations. To fill this potential "hole", we suggest the "in advance of real time" be replaced with "one or more hours prior to real time", which the real time being understood, or defined, to be current hour. Alternatively, the phrase could be replaced with "beyond the current hour".
Response: The proposed modification was not adopted. The intent of this requirement is to ensure that, in real-time and the day ahead, the Reliability Coordinator is prepared to take whatever actions necessary, to prevent and/or mitigate instances of violating IROLs. There is no hole in the reliability process because if the Operational Planning Analysis does not project the potential IROL violation, then at a minimum, the next Real-time Assessment will detect it. It isn't possible to have a plan for every possible instance of exceeding an IROL. The term, 'real-time' is defined as follows in the NERC Glossary of Terms Used in Reliability Standards: Present time as opposed to future time. Thus, we cannot make an assumption that "real-time" means the current hour.		
FirstEnergy	No	It should be clear that the main intent is to have IROL mitigation plans in place for the current operating day. For clarity, we suggest the following replacements for requirements R1 and R2. R1 For the current day operating conditions, each Reliability Coordinator shall have Operating Processes, Procedures or Plans that identify mitigation actions it shall take or actions it shall direct others to take up to and including load shedding that can be implemented in time to prevent exceeding any of its IROL conditions. The mitigation actions shall be available one or more days prior to the current operating day. R2 For the current day operating conditions, each Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify mitigation actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding any of its IROL conditions, such that the IROL is relieved within the IROL's Tv. The mitigation actions shall be available one or more days prior to the current operating day.
Response: The main intent of this standard is to be prepared for identified IROLs in any operating horizon. The proposed language states that you must have a plan for "all" IROLs identified one or more days prior to the current day –it isn't possible to have a plan for every possible IROL.		
ISO New England Inc	No	With this change one could interpret that the RC does not need to prepare for action plans for those IROLs not identified in "real-time," which (we believe) is not the intent. We therefore suggest the "in advance of real-time" be replaced with "one or more hours prior to real-time", with real-time being defined as the current hour.
Response: The proposed modification was not adopted. The intent of this requirement is to ensure that, in real time and the day ahead, the Reliability Coordinator is prepared to take whatever actions necessary, to prevent and/or mitigate instances of violating IROLs.		

There is no hole in the reliability process because if the operational planning analysis does not project the potential IROL violation, then at a minimum, the next real-time assessment will detect it. It isn't possible to have a plan for every possible instance of exceeding an IROL.		
American Transmission Company LLC	Yes	ATC agrees that the phrase "one or more days prior to the current day" provides additional clarity.
Response: The drafting team appreciates your support of this modification.		
Entergy Services	Yes	
RCCWG - reliability coordinator comments working group	Yes	
Manitoba Hydro	Yes	
Operating Reliability Working Group	Yes	
SERC OC Standards Review Group - IROL Standards, IRO-008-1, 009-1, 010-1	Yes	
San Diego Gas and Electric Co.	Yes	
Hydro One Networks	Yes	

5. The drafting team modified the Violation Severity Levels for IRO-009. Do you agree with the new VSLs?

Summary Consideration: Most comenters who disagreed with the proposed VSLs made one of the following recommendations:

Eliminate the "High" VSL for Requirement R3 because the VSL focuses on the quality of the action plan rather than on whether action was taken. The drafting team reviewed the requirement and confirmed that the requirement is focusing on 'acting' and eliminated the "High" VSL as proposed.

Eliminate the first of the two conditions for Requirement 4 that could result in a "Severe" VSL. The drafting team did adopt this suggestion as the second condition, by itself, fully described the noncompliant performance that meets the criteria for a "Severe" VSL.

Eliminate the "Severe" VSL for Requirement R4 when the Reliability Coordinator makes an unsuccessful attempt to return the system to within its IROLs within the IROL's T_v or move the VSL to "High". The suggestion to modify the VSLs and make the VSL "High" if the Reliability Coordinator make an attempt to resolve the IROL within the IROL's T_v was not adopted because if the Reliability Coordinator does not resolve the IROL within the IROL's T_v, then the intent of the requirement has not been met at all – and this type of violation is classified as a "Severe" VSL.

Organization/Group		Question 5 Comments:
Northeast Utilities	No	We agree with all of the VSLs except one. The second Severe condition for R4 appears to be giving no recognition that the RC did take corrective actions without delay (within 5 minutes) but was unable to correct the situation of IROL being exceeded. We suggest that this be moved to High as the second condition. In fact, R4 contains 2 requirements: a. take actions without delay (within 5 minutes) and correct the situation of IROL being exceeded. Hence, if an RC fails to perform either one, its violation is deemed to be high. If it fails to perform both, then it is deemed to have fully violated the requirement which is severe.
Response: The Reliability Coordinator is the functional entity with the highest level of authority – and the Reliability Coordinator must execute its authority to resolve any IROL with its T_v because of the potential impact on the interconnection if the IROL is exceeded for time greater than IROL T_v - instability, uncontrolled separation, or cascading outages. The suggestion to modify the VSLs and make the VSL "High" if the Reliability Coordinator make an attempt to resolve the IROL within the IROL's Tv was not adopted because if the Reliability Coordinator does not resolve the IROL within the IROL's T_v, then the intent of the requirement has not been met at all – and this type of violation is classified as a "Severe" VSL.		
NPCC Regional Standards Committee, RSC	No	We agree with all of the VSLs except one. The second Severe condition for R4 appears to be giving no recognition that the RC did take corrective actions without delay (within 5 minutes) but was unable to correct the situation of IROL being exceeded. We suggest that this be moved to High as the second condition. In fact, R4 contains 2 requirements: a. take actions without delay (within 5 minutes) and correct the situation of IROL being exceeded. Hence, if an RC fails to perform either one, its violation is deemed to be high. If it fails to perform both, then it is deemed to have fully violated the requirement which is severe.

<table>
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</table>

Organization/Group		Question 5 Comments:
Hydro-Québec TransEnergie	No	HQT agree with all of the VSLs except one. The second Severe condition for R4 appears to be giving no recognition that the RC did take corrective actions without delay (within 5 minutes) but was unable to correct the situation of IROL being exceeded. We suggest that this be moved to High as the second condition. In fact, R4 contains 2 requirements: a. take actions without delay (within 5 minutes) and correct the situation of IROL being exceeded. Hence, if an RC fails to perform either one, its violation is deemed to be high. If it fails to perform both, then it is deemed to have fully violated the requirement which is severe.
Response: The Reliability Coordinator is the functional entity with the highest level of authority – and the Reliability Coordinator must execute its authority to resolve any IROL with its T_v because of the potential impact on the interconnection if the IROL is exceeded for time greater than IROL T_v - instability, uncontrolled separation, or cascading outages. The suggestion to modify the VSLs and make the VSL "High" if the Reliability Coordinator make an attempt to resolve the IROL within the IROL's Tv was not adopted because if the Reliability Coordinator does not resolve the IROL within the IROL's T_v, then the intent of the requirement has not been met at all – and this type of violation is classified as a "Severe" VSL.		
Hydro One Networks	No	We agree with the VSLs for requirements 1 and 2. However the high VSL for requirement 3 is not appropriate because it tries to judge the effectiveness of the Operating Processes, Procedures or Plans. Requirement 4 provides for judgment of the effectiveness of the Processes, Procedures or Plans on a basis of being able to mitigate the exceeded IROL within the its Tv. As well, R4 includes two requirements: 1) act or direct, without delay, to mitigate the instance of exceeding the IROL; 2) mitigate this instance within the Tv. We suggest that if the RC does not meet both requirements the violation level should be severe and if the RC does not meet one of the requirements the violation level should be high.
Response: The team removed the "High" VSL for R3 in support of your comment. The requirement is to "act" not to "prevent". The Reliability Coordinator is the functional entity with the highest level of authority – and the Reliability Coordinator must execute its authority to resolve any IROL within its T_v because of the potential impact on the interconnection if the IROL is exceeded for time greater than IROL T_v -- instability, uncontrolled separation, or cascading outages. The suggestion to modify the VSLs and make the VSL "High" if the Reliability Coordinator make an attempt to resolve the IROL within the IROL's Tv was not adopted because if the Reliability Coordinator does not resolve the IROL within the IROL's T_v, then the intent of the requirement has not been met at all – and this type of violation is classified as a "Severe" VSL.		
RCCWG - reliability coordinator comments working group	No	R4 High- in the VSL does "acting and directing" include contacting the entity and gathering information and data or does it strictly mean issuing a directive? R5 Severe - eliminate the top VSL, this describes how a failure to mitigate occurred, the issue is there was a failure to mitigate. Also, if an RC issues a directive to mitigate an IROL and the entity fails to comply or is unable to comply is the RC in violation of this requirement?
Response: The requirement is as stated – acting or directing. Contacting the entity could be evidence of acting, and if there were evidence of the contact, then this would be considered acting "without delay." There could also be other types of "acting" – such as calling up screen displays to research the problem – or noting in the log that an action already taken just before the instance of exceeding the IROL was expected to resolve the IROL within its T_v and no further action is needed. The drafting team believes you intended to reference Requirement R4 rather than R5 – and the drafting team did eliminate the top VSL. The		

Organization/Group		Question 5 Comments:
Reliability Coordinator is the functional entity with the highest level of authority – and the Reliability Coordinator must execute its authority to resolve any IROL within its T_v because of the potential impact on the interconnection - instability, uncontrolled separation, or cascading outages. If a Reliability Coordinator issues a directive that some other entity does not comply with, then the Reliability Coordinator is still responsible for preventing the violation of the IROL for time greater than the IROL's T_v.		
Operating Reliability Working Group	No	The High VSL for R4 contains an additional requirement that is not in R4. The VSL defines 'without delay' as being five minutes or less. The 'five minute' requirement should be deleted from the VSL.
Response: The drafting team does not believe that it has added a new requirement. The standard uses the language "without delay" and the measures look for types of evidence that could be reasonably interpreted as evidence that the Reliability Coordinator took some action – making a phone call, acknowledging an alarm, calling up an EMS display – all of these are evidence that the Reliability Coordinator took some recordable action to investigate the situation and respond to remedy the situation. The drafting team did not intend for the "5 minutes" to mean that a directive had to be issued within that 5 minutes.		
American Transmission Company LLC	No	Severe VSL for R4ATC does not agree with the language in the Severe VSL for Requirement 4. The purpose of this VSL is for a Tv violation. ATC recommends that the first description be deleted and only the second description be kept. If the SDT does not agree they should provide a reason for the two descriptions.
Response: The drafting team adopted your suggestion to delete the first description of a Severe VSL from R4.		
SERC OC Standards Review Group - IROL Standards, IRO-008-1, 009-1, 010-1	No	1. The Violation Security Levels for R3 and R4 impose additional requirements that are not in the standard. For R3, it seems inappropriate that the Violation Severity Level should be based upon the effectiveness of the plan to prevent the system from entering an IROL in real-time. The dynamics topology and unit commitment/dispatch of an electric system are constantly changing and no specific occurrence of an SOL or IROL can be accurately represented in planning case studies. It is thus impractical or impossible to devise a perfect process for mitigating each and every instance during which a known IROL may manifest and persist as conditions change during the IROL Tv. 2. In R4, if the trigger limit for initiating action is five (5) minutes, then that limit should be explicitly included in the requirements and not introduced for the first time in the measurement criteria. Furthermore, we feel that a time of five (5) minutes is arbitrary and implementation of correct action is the primary requirement. Operators will be under tremendous pressure to work out a solution when an IROL is exceeded and satisfy the five minute requirement. We feel that it is more important to 1) recognize that an IROL has been violated, 2) determine the correct process or procedure required to mitigate the identified IROL, 3) modify the identified generic process or procedure to meet specific real time system conditions as required and, 4) implement the modified process or procedure while at the same time maintaining continuous communications with all parties involved and simultaneously documenting actions being taken as required for NERC audits. It is not clear to us exactly how the five (5) minute trigger adds any value to this process. If the goal is to mitigate the IROL within the IROL Tv, and the actions are successful, what impact does a five (5) minute trigger requirement add to the process? WE STRONGLY SUGGEST THAT THE "HIGH" SEVERITY LEVEL SHOULD BE ELIMINATED FOR R3 AND R4.
Response: 1. The drafting team removed the High VSL for R3 based on stakeholder comments indicating that the VSL is inappropriate because it judges the quality of the actions – the Requirement is to "act" not to "prevent."		

Organization/Group		Question 5 Comments:
The intent of R4 is for the Reliability Coordinator to act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's T_v. Note that many entities include a default paragraph that is included in all of its operating procedures that clearly gives the real-time system operator the authority to use operating knowledge and experience to deviate from a plan when the actual system conditions don't match the studied or planned conditions. Adding this paragraph allows the system operator to make modifications to the plans, as needed, to achieve the objective of preventing or mitigating the instance of exceeding an IROL. 2. The drafting team did not modify the standard to include the reference to the 5 minute delay because this sends a message that it is acceptable to wait before taking action – the intent of the 5 minute period was to provide a boundary prior to which there needed to be some recordable action to demonstrate that action had been taken. The standard uses the language "without delay" and the measures look for types of evidence that could be reasonably interpreted as evidence that the RC took some action – making a phone call, acknowledging an alarm, calling up an EMS display – all of these are evidence that the RC took some recordable action to investigate the situation and respond to remedy the situation. The drafting team did not intend for the "5 minutes" to mean that a directive had to be issued within that 5 minutes.		
FirstEnergy	Yes	For R4, Severe VSL - We recommend retaining only the text below the "OR" statement. The text above is duplicative and adds no additional value since the end result is that the IROL is not mitigated within the allowable Tv timeframe.
Response: The drafting team adopted this suggestion and deleted the text above the "OR" for the severe VSL for R4. We thank you for your support.		
Entergy Services	Yes	
Manitoba Hydro	Yes	
San Diego Gas and Electric Co.	Yes	

6. The drafting team modified the Violation Severity Levels for IRO-010. Do you agree with the new VSLs?

Summary Consideration: While most stakeholders who responded to this question indicated agreement with the proposed VSLs, some stakeholders indicated that the VSLs for R1 should be modified to reflect that missing a process for obtaining real-time operating data when it becomes unavailable contributes more to the intent of the requirement than having the data in the wrong format – and the drafting team modified the VSLs for R1 to reflect this.

Organization/Group	6:	Question 6 Comments:
RCCWG - reliability coordinator comments working group	No	What is the expectation for the process when your automated data is not available? Does freezing the State Estimator value and then getting data via phone and fax suffice?
Response: Requirement R1.4 states that the Reliability Coordinator's data specification must include the following: Process for data provision when automated Real-Time system operating data is unavailable. The standard does not specify "how" to provide the data to the Reliability Coordinator. Freezing the state estimator values and getting the data via phone may be acceptable to the Reliability Coordinator.		
Manitoba Hydro	No	R1 - What constitutes a "complete data specification"? TOP-005-0 Attachment 1, which will become a Technical Reference, needs a tune up. What is the determining factors when identifying transmission and other facilities as "key"? What size of generator is the RC concerned with in regards to on/off status, AVR status, PPS status, MW & Mvar output?
Response: Agree that the attachment needs a "tune up" – it is not comprehensive enough to meet the data needs of all Reliability Coordinators. In Order 693, FERC did direct that special protection systems should be added to the list of items in Attachment 1. Note that the revised implementation plan no longer recommends the retirement of Attachment 1. TOP-005 R3 references this Attachment so it is still needed in the standard. Each Reliability Coordinator has the authority to identify what data it needs – and the data specification must address all subrequirements in Requirement R1.		
Operating Reliability Working Group	No	The Lower and Moderate VSLs for R1 should be reversed. We believe that it is more important to have a process for obtaining real-time operating data when it becomes unavailable than having the data in the wrong format. At least you have the data.
Response: Agreed – the drafting team adopted your suggestion and switched the VSLs.		
San Diego Gas and Electric Co.	No	In the revised IRO-010 Violation Severity Levels Table, there is no provision for less than 100% compliance for real-time data sent by the TO/TOP to the RC. Providing data at a level greater than 95% but less than 100% is cause for a "Lower" Violation Severity Level. That level rises as less data is provided, to a maximum of "Severe" when less than 75% of the requested data is sent to the RC. Real time data typically has some level of availability associated with it that allows for the inherent nature of real time data being less than 100% complete. Examples may include the failure of field equipment such as RTUs, communication circuits, instrumentation, and other events

Organization/Group	6:	Question 6 Comments:
		that could impact 100% data availability such as missed RTU scans, loss of data when systems are being shifted to backup EMS systems, etc. Requirement R3 and the Violation Severity Level Violation table need to be re-written to correlate with Requirement 1.4 that would include an exemption for short-term real time data failures or outages when determining the Violation Severity Level, perhaps with language such as "excluding unavailable real-time data (R1.4)."
Response: The VSL is only applied when there has been an identified violation – the VSLs provide up to four categories of noncompliant performance that might have been seen by the Compliance Enforcement Authority when it assessed compliance. Under R1.4 any acceptable tolerance for missing data will be included in the Reliability Coordinator's data specification.		
Hydro One Networks	No	We agree with VSLs for R2 and R3 however, we disagree with the VSLs for R1. Example, failing to specify a process for data provision when the automated Real-time system operating data is unavailable could result in the RC being "blind" to what is going on in the system and render them unable to act or direct others to act. We suggest that missing any one of R1's sub-requirements is a High VSL and having no data specification is a Severe VSL.
Response: Based on other comments, the drafting team did modify the Lower and Moderate VSLs so that the failure to comply with R1.2 is now "lower" and failure to comply with R1.4 is "moderate". The drafting team attempted to use all four categories of VSLs to provide the compliance enforcement authority with as many options for categorizing noncompliant performance as practicable.		
American Transmission Company LLC	No	VSL for R3: The VSLs do not seem to take into account the frequency of not sending the data. The SDT should provide additional detail within each VSL. How will the percentage be determined over time?
Response: The data specification must identify how often data and information must be supplied – the VSLs only categorize the severity of the violation when the data and information was not provided 'as specified' in the Reliability Coordinator's data specification. The VSL is only applied when there has been an identified violation – the VSLs provide up to four categories of noncompliant performance that might have been seen by the compliance enforcement authority when it assessed compliance.		
Northeast Utilities	Yes	
NPCC Regional Standards Committee, RSC	Yes	
Hydro-Québec TransEnergie	Yes	
Entergy Services	Yes	
SERC OC Standards Review Group - IROL Standards, IRO-008-1, 009-1, 010-1	Yes	

Organization/Group	6:	Question 6 Comments:
Ontario IESO	Yes	
ISO RTO Council Standards Review Committee	Yes	
FirstEnergy	Yes	
ISO New England Inc	Yes	

7. The drafting team modified the implementation plan to reflect the modifications made based on the elimination of IRO-007-1 Requirement R1. Do you agree with the modifications made to the implementation plan?

Summary Consideration: Many stakeholders who responded to this question disagreed with the recommended retirement of EOP-001 R2 and the recommended modification of IRO-005 R13. In each case the drafting team considered the comments provided, but continues to recommend the retirements or revisions for the reasons provided below.

EOP-001 R2 – The reason stated for objecting to the recommended retirement of EOP-001 Requirement R2 was aimed at concern that eliminating this requirement would eliminate the requirement that the Transmission Operator have load reduction plans in place that can be executed within 30 minutes.

Here are Requirements R2, R3, and parts of R4 from EOP-001:

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

The drafting continues to recommend the retirement of EOP-001 R2 for the following reasons:

The retirement of the EOP-001 R2 does not resolve the Transmission Operator from having emergency load reduction plans – EOP-001 R3.3 and R4.2 (shown in blue above) still apply to the Transmission Operator and require the Transmission Operator to develop, maintain and implement a set of plans for load shedding that can be executed within the necessary timeline.

The existing EOP-001 R2 gives the impression that all load reduction plans developed to bring the system to within IROLs must be capable of success within 30 minutes – and that doesn't support the new requirements which state the IROL must be resolved within the IROL's T_v, which can be shorter than 30 minutes.

The existing EOP-001 R2 gives the impression that load reduction plans are the only types of plans that can be developed in advance to resolve IROLs, and that isn't technically correct. Implementing a load reduction plan is one of several different methods that can be used to resolve IROLs.

IRO-004 R4 – The reason stated for objecting to the retirement of the following requirement from IRO-005 R4 is that the requirement is intended to provide system information not just for the RC within whose area the BA, TOP, etc. reside, but also for other RCs and TOPs, TSPs for system modeling/consideration for their respective specific uses.

R4. Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

The drafting continues to recommend the retirement of IRO-004 R4 for the following reason:

Although the commenters indicate that the intent of this requirement is to provide data to entities other than the Reliability Coordinator, the drafting team disagrees. The intent of IRO-004 R4 is to provide data to Reliability Coordinators. TOP-002 is focused on requiring the Transmission Operators to collect the data they need for their own analyses.

IRO-005 R13 – The reason stated for objecting to the retirement of the following text from IRO-005 Requirement R13 is that the same language is not covered in any of the new standards:

R13. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection.

The drafting team continues to recommend the retirement of the first sentence in IRO-005 R13 for the following reason:

The first sentence in IRO-005 R13 assumes that the Reliability Coordinator can see all System Operating Limits and has direct communication with all operating entities. The Reliability Coordinator doesn't necessarily see the actions of the Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities to direct them with respect to operating within SOLs. The Reliability Coordinator sees the effect of their actions, and directs actions for the Generator Operators, Transmission Service Providers, Load-serving Entities and Purchasing-selling Entities through Transmission Operators and Balancing Authorities.

In addition, during the development of the measures and compliance elements for IRO-005, the Missing Measures and Compliance Elements Drafting Team determined that it could not develop a measure for the first sentence in R13 because the Reliability Coordinator cannot ensure that entities will "operate to prevent the likelihood" of something happening.

Organization/Group		Question 7 Comments:
Northeast Utilities	No	We agree with some but not all of the proposed changes to the other standards. (1) EOP-001 R2: We do not agree with removing this requirement, which says: "The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes." This requirement does not equate to the Transmission Operator developing plans for mitigating IROLs, which is the role of the RC. In fact, this requirement holds the TOP responsible for having the load reduction plan in place ahead of real time so that when directed by the RC, it can execute the plan to assist in mitigating the IROL violation. While the IRO-008 to IRO-010 standards give the RC the authority and the flexibility to direct the TOP to do so, having the plan in advance and be ready for execution is not covered by these IRO standards. Further, the amount and timing that the TOP is able to achieve with load reduction must be known to the RC ahead of real time for it to consider the effectiveness of the plan's execution in support of the mitigating action. (2) IRO-002 R2: We agree with retiring this requirement. (3) IRO-004-1 ? Reliability Coordination? Operations Planning: retire entire standard (R1 through R6). We agree with retiring this standard since all requirements are covered elsewhere except R4. This requirement is intended to provide system information not just for the RC within whose area the BA, TOP, etc. reside, but also for other RCs and TOPs, TSPs for system modeling/consideration for their respective specific uses. This requirement needs to be incorporated in an appropriate standard. (4) IRO-005-2? Reliability Coordination? Current Day Operations: Retire R2, R3, and R5; modify R9, R13 and R14; retire R16 and R17. (a) We agree with retiring R2, R3, R5, R16 and R17, and revising R9 and R14. (b) For R13, the Implementation Plan says "retiring" but it should read "revising". We agree with the proposed revision to the part on operating to the most limiting parameter, but do not agree with retiring that part pertaining to ensuring the SOLs and IROLs are not exceeded. This part, which reads: "Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection." R13 actually contains two requirements that are not covered by the new IRO-009:

Organization/Group		Question 7 Comments:
		(a) IRO-009 deals with IROL only; the RC needs also to be aware of the SOL situation since an SOL may become an IROL as system conditions change. (b) the requirement also holds the RC responsible for ensuring that the entities within the RC area operate to prevent situations that could result in a SOL or IROL violation in another area of the Interconnection." This is not covered by the new IRO-009. We therefore suggest that R13 be retained with only the revision to remove "Reliability Coordinator and its" from the second sentence. (5) TOP-003-0? Planned Outage Coordination Modify R1.2. We agree with this change. (6) TOP-005-1? Operational Reliability Information: Retire R1 and R1.1 and convert Attachment 1 into a reference. We agree with retiring R1 and R1.1 and the proposed conversion of Attachment 1 into a reference. But there doesn't seem to be a draft reference document posted. When the new IRO standards go into effect, the reference documents will need to be available. Please elaborate on the timing and the process for posting and implementing the reference. (7) TOP-006-1? Monitoring System Conditions Voltage and Reactive Control: Modify R4. We agree with this change.

Response:
EOP-001 R2 - The drafting team believes that load reduction plans are just one of many tools that can be used to resolve IROLs.

IRO-004 R4 - The requirement does not specify what functional entity receives the data – but the standard is built on the assumption that the data is provided to the Reliability Coordinator – there are no requirements in the standard for any entity to use the data, except the Reliability Coordinator.

The IRO standards are intended to address reliability coordination at the Reliability Coordination level – implying that IRO-004 R4 requires data to be shared with the Transmission Operator and Transmission Service Provider seems to be implying more than what was intended. TOP-002 is focused on requiring the Transmission Operators to collect the data they need for their own analyses.

IRO-005 R13 - The drafting team agrees that the implementation plan should have indicated that drafting team recommends, “revising” R13 and has corrected this typographical error.

IRO-005 R13 - The first requirement in IRO-015 R13 assumes that the Reliability Coordinator can see all System Operating Limits, and this is not always true. The Reliability Coordinator is responsible for seeing IROLs and controlling operations within its Reliability Coordinator Area so as to prevent instances of exceeding IROLs. If the Reliability Coordinator has a System Operating Limit that it knows can become an IROL, then that Reliability Coordinator should be operating so as to preclude exceeding that limit.

The drafting team believes that the second part of R13 that is proposed for deletion is technically incorrect as currently embodied in the standard. The Reliability Coordinator does oversee the actions of the Transmission Operators and Balancing Authorities, and there are requirements that

Organization/Group		Question 7 Comments:
address Reliability Coordinator actions to keep these entities operating within limits, but the Reliability Coordinator doesn't necessarily see the actions of the Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities to direct them with respect to operating within SOLs. The Reliability Coordinator sees the effect of their actions, and directs actions for the Generator Operators, Transmission Service Providers, Load-serving Entities and Purchasing-selling Entities through Transmission Operators and Balancing Authorities. TOP-005 – Attachment 1 - The revised implementation plan no longer recommends the retirement of Attachment 1. TOP-005 R3 references this Attachment so it is still needed in the standard.		
NPCC Regional Standards Committee, RSC	No	We agree with some but not all of the proposed changes to the other standards. (1) EOP-001 R2: We do not agree with removing this requirement, which says: "The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes." This requirement does not equate to the Transmission Operator developing plans for mitigating IROLs, which is the role of the RC. In fact, this requirement holds the TOP responsible for having the load reduction plan in place ahead of real time so that when directed by the RC, it can execute the plan to assist in mitigating the IROL violation. While the IRO-008 to IRO-010 standards give the RC the authority and the flexibility to direct the TOP to do so, having the plan in advance and be ready for execution is not covered by these IRO standards. Further, the amount and timing that the TOP is able to achieve with load reduction must be known to the RC ahead of real time for it to consider the effectiveness of the plan's execution in support of the mitigating action. (2) IRO-002 R2: We agree with retiring this requirement. (3) IRO-004-1 ? Reliability Coordination? Operations Planning: retire entire standard (R1 through R6). We agree with retiring this standard since all requirements are covered elsewhere except R4. This requirement is intended to provide system information not just for the RC within whose area the BA, TOP, etc. reside, but also for other RCs and TOPs, TSPs for system modeling/consideration for their respective specific uses. This requirement needs to be incorporated in an appropriate standard. (4) IRO-005-2? Reliability Coordination? Current Day Operations: Retire R2, R3, and R5; modify R9, R13 and R14; retire R16 and R17. (a) We agree with retiring R2, R3, R5, R16 and R17, and revising R9 and R14. (b) For R13, the Implementation Plan says "retiring" but it should read "revising". We agree with the proposed revision to the part on operating to the most limiting parameter, but do not agree with retiring that part pertaining to ensuring the SOLs and IROLs are not exceeded. This part, which reads: "Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL

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		or IROL violation in another area of the Interconnection." R13 actually contains two requirements that are not covered by the new IRO-009: (a) IRO-009 deals with IROL only; the RC needs also to be aware of the SOL situation since an SOL may become an IROL as system conditions change. (b) the requirement also holds the RC responsible for ensuring that the entities within the RC area operate to prevent situations that could result in a SOL or IROL violation in another area of the Interconnection." This is not covered by the new IRO-009. We therefore suggest that R13 be retained with only the revision to remove "Reliability Coordinator and its" from the second sentence. (5) TOP-003-0? Planned Outage Coordination Modify R1.2. We agree with this change. (6) TOP-005-1? Operational Reliability Information: Retire R1 and R1.1 and convert Attachment 1 into a reference. We agree with retiring R1 and R1.1 and the proposed conversion of Attachment 1 into a reference. But there doesn't seem to be a draft reference document posted. When the new IRO standards go into effect, the reference documents will need to be available. Please elaborate on the timing and the process for posting and implementing the reference. (7) TOP-006-1? Monitoring System Conditions Voltage and Reactive Control: Modify R4. We agree with this change.
Response: Please see the Summary Consideration and the Response to Northeast Utilities.		
Hydro-Québec TransEnergie	No	HQT agree with some but not all of the proposed changes to the other standards. (1) EOP-001 R2: We do not agree with removing this requirement, which says: "The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes." This requirement does not equate to the Transmission Operator developing plans for mitigating IROLs, which is the role of the RC. In fact, this requirement holds the TOP responsible for having the load reduction plan in place ahead of real time so that when directed by the RC, it can execute the plan to assist in mitigating the IROL violation. While the IRO-008 to IRO-010 standards give the RC the authority and the flexibility to direct the TOP to do so, having the plan in advance and be ready for execution is not covered by these IRO standards. Further, the amount and timing that the TOP is able to achieve with load reduction must be known to the RC ahead of real time for it to consider the effectiveness of the plan's execution in support of the mitigating action. (2) IRO-002 R2: We agree with retiring this requirement. (3) IRO-004-1 ? Reliability Coordination? Operations Planning: retire entire standard (R1 through R6). We agree with retiring this standard since all requirements are covered elsewhere except R4. This requirement is intended to provide system information not just for the RC within whose area the BA, TOP, etc. reside, but also for other RCs and TOPs, TSPs for system modeling/consideration for their respective specific uses. This requirement needs to be

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		incorporated in an appropriate standard. (4) IRO-005-2? Reliability Coordination? Current Day Operations: Retire R2, R3, and R5; modify R9, R13 and R14; retire R16 and R17. (a) We agree with retiring R2, R3, R5, R16 and R17, and revising R9 and R14. (b) For R13, the Implementation Plan says "retiring" but it should read "revising". We agree with the proposed revision to the part on operating to the most limiting parameter, but do not agree with retiring that part pertaining to ensuring the SOLs and IROLs are not exceeded. This part, which reads: "Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection." R13 actually contains two requirements that are not covered by the new IRO-009: (a) IRO-009 deals with IROL only; the RC needs also to be aware of the SOL situation since an SOL may become an IROL as system conditions change. (b) the requirement also holds the RC responsible for ensuring that the entities within the RC area operate to prevent situations that could result in a SOL or IROL violation in another area of the Interconnection." This is not covered by the new IRO-009. We therefore suggest that R13 be retained with only the revision to remove "Reliability Coordinator and its" from the second sentence. (5) TOP-003-0? Planned Outage Coordination Modify R1.2. We agree with this change. (6) TOP-005-1? Operational Reliability Information: Retire R1 and R1.1 and convert Attachment 1 into a reference. We agree with retiring R1 and R1.1 and the proposed conversion of Attachment 1 into a reference. But there doesn't seem to be a draft reference document posted. When the new IRO standards go into effect, the reference documents will need to be available. Please elaborate on the timing and the process for posting and implementing the reference. (7) TOP-006-1? Monitoring System Conditions Voltage and Reactive Control: Modify R4. We agree with this change.
Response: Please see the Summary Consideration and the Response to Northeast Utilities.		
Ontario IESO	No	We agree with some but not all of the proposed changes to the other standards. (1) EOP-001 R2: We do not agree with removing this requirement, which says: "The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented

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		within 30 minutes." This requirement does not equate to the Transmission Operator developing plans for mitigating IROLs, which is the role of the RC. In fact, this requirement holds the TOP responsible for having the load reduction plan in place ahead of real time so that when directed by the RC, it can execute the plan to assist in mitigating the IROL violation. While the IRO-008 to IRO-010 standards give the RC the authority and the flexibility to direct the TOP to do so, having the plan in advance and be ready for execution is not covered by these IRO standards. Further, the amount and timing that the TOP is able to achieve with load reduction must be known to the RC ahead of real time for it to consider the effectiveness of the plan's execution in support of the mitigating action. (2) IRO-002 R2: We agree with retiring this requirement. (3) IRO-004-1 ? Reliability Coordination? Operations Planning: retire entire standard (R1 through R6). We agree with retiring this standard since all requirements are covered elsewhere except R4. This requirement is intended to provide system information not just for the RC within whose area the BA, TOP, etc. reside, but also for other RCs and TOPs, TSPs for system modeling/consideration for their respective specific uses. This requirement needs to have a "home". (4) IRO-005-2? Reliability Coordination? Current Day Operations: Retire R2, R3, and R5; modify R9, R13 and R14; retire R16 and R17. (a) We agree with retiring R2, R3, R5, R16 and R17, and revising R9 and R14. (b) For R13, the Implementation Plan says "retiring" but it should read "revising". We agree with the proposed revision to the part on operating to the most limiting parameter, but do not agree with retiring that part pertaining to ensuring the SOLs and IROLs are not exceeded. This part, which reads: "Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection" actually contains two requirements that are not covered by the new IRO-009: (a) IRO-009 deals with IROL only; the RC needs also to be aware of the SOL situation since an SOL may become an IROL as system conditions change. (b) the requirement also holds the RC responsible for ensuring that the entities within the RC area operate to prevent situations that could result in a SOL or IROL violation in another area of the Interconnection." This is not covered by the new IRO-009. We therefore suggest that R13 be retained with only the revision to remove "Reliability Coordinator and its" from the second sentence. (5) TOP-003-0? Planned Outage Coordination Modify R1.2. We agree with this change.

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Response: Please see the Summary Consideration and the Response to Northeast Utilities.		
ISO RTO Council Standards Review Committee	No	We do not agree with all of the proposed changes. (1) EOP-001 R2: We do not agree with removing this requirement, which says: "The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes." This requirement does not equate to the Transmission Operator developing plans for mitigating IROLs, which is the role of the RC. In fact, this requirement holds the TOP responsible for having the load reduction plan in place ahead of real time so that when directed by the RC, it can execute the plan to assist in mitigating the IROL violation. While the IRO-008 to IRO-010 standards give the RC the authority and the flexibility to direct the TOP to do so, having the plan in advance and be ready for execution is not covered by these IRO standards. Further, the amount and timing that the TOP is able to achieve with load reduction must be known to the RC ahead of real time for it to consider the effectiveness of the plan's execution in support of the mitigating action. (2) IRO-002 R2: We agree with retiring this requirement. (3) IRO-004-1 ? Reliability Coordination? Operations Planning: retire entire standard (R1 through R6). We agree with retiring this standard since all requirements are covered elsewhere except R4. This requirement is intended to provide system information not just for the RC within whose area the BA, TOP, etc. reside, but also for other RCs and TOPs, TSPs for system modeling/consideration for their respective specific uses. This requirement needs to have a "home". (4) IRO-005-2? Reliability Coordination? Current Day Operations: Retire R2, R3, and R5; modify R9, R13 and R14; retire R16 and R17. (a) We agree with retiring R2, R3, R5, R16 and R17, and revising R9 and R14. (b) For R13, the Implementation Plan says "retiring" but it should read "revising". We agree with the proposed revision to the part on operating to the most limiting parameter, but do not agree with retiring that part pertaining to ensuring the SOLs and IROLs are not exceeded. This part, which reads: "Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL

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Response: Please see the Summary Consideration and the Response to Northeast Utilities.		
ISO New England Inc	No	We do not agree with all of the proposed changes. (1) EOP-001 R2: We do not agree with removing this requirement, which says: "The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes." This requirement does not equate to the Transmission Operator developing plans for mitigating IROLs, which is the role of the RC. In fact, this requirement holds the TOP responsible for having the load reduction plan in place ahead of real time so that when directed by the RC, it can execute the plan to assist in mitigating the IROL violation. While the IRO-008 to IRO-010 standards give the RC the authority and the flexibility to direct the TOP to do so, having the plan in advance and be ready for execution is not covered by these IRO standards. Further, the amount and timing that the TOP is able to achieve with load reduction must be known to the RC ahead of real time for it to consider the effectiveness of the plan's execution in support of the mitigating action. (2) IRO-002 R2: We agree with retiring this requirement. (3) IRO-004-1: We agree with retiring this standard since all requirements are covered elsewhere except R4. This requirement is intended to provide system information not just for the RC within whose area the BA, TOP, etc.

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		reside, but also for other RCs and TOPs, TSPs for system modeling/consideration for their respective specific uses. This requirement needs to have a "home". (4) IRO-005-2: Retire R2, R3, and R5; modify R9, R13 and R14; retire R16 and R17. (a) We agree with retiring R2, R3, R5, R16 and R17, and revising R9 and R14. (b) For R13, the Implementation Plan says "retiring" but it should read "revising". We agree with the proposed revision to the part on operating to the most limiting parameter, but do not agree with retiring that part pertaining to ensuring the SOLs and IROLs are not exceeded. This part, which reads: "Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection." actually contains two requirements that are not covered by the new IRO-009: (a) IRO-009 deals with IROL only; the RC needs also to be aware of the SOL situation since an SOL may become an IROL as system conditions change. (b) the requirement also holds the RC responsible for ensuring that the entities within the RC area operate to prevent situations that could result in a SOL or IROL violation in another area of the Interconnection." This is not covered by the new IRO-009. We therefore suggest that R13 be retained with only the revision to remove "Reliability Coordinator and its" from the second sentence. (5) TOP-003-0: Modify R1.2. We agree with this change. (6) TOP-005-1: Retire R1 and R1.1 and convert Attachment 1 into a reference. We agree with retiring R1 ad R1.1 and the proposed conversion of Attachment 1 into a reference. (7) TOP-006-1: Modify R4. We agree with this change.
Response: Please see the Summary Consideration and the Response to Northeast Utilities.		
Hydro One Networks	No	We do not agree with the elimination of EOP-001-0 R2 as the RC and TOP must work together in planning how to implement load reduction. We do not agree with retiring R3 of IRO-004-1. Where SOLs and IROLs are known at least a day prior to the current day, the RC should have enough time to "coordinate" the development of action plans required to return transmission loading to within acceptable SOLs and IROLs with its Transmission Operators and Balancing Authorities. Otherwise how does the RC know if their plan is feasible or effective? Developing "effective" plans to mitigate SOLs and IROLs are a operation planning function and therefore belong in the IRO-004-1 Reliability Coordination - Operations Planning standard.

Organization/Group		Question 7 Comments:
		We do not agree with the retirement of IRO-005-2 R5. We agree that the RC may not be the responsible entity for SOLs violations however; it would be more prudent to modify the requirement instead of retiring it completely. Perhaps take "SOL" out of the requirement and create a new requirement having the TOP responsible for SOL violations. There is confusion on whether you want to retire or modify IRO-005-2 R13 (page 3 verses page 20). We suggest modifying R13 by separating it into two separate requirements. The first having the RC responsible for ensuring all entities operate to prevent actions in their Reliability Coordinator Area that results in IROL violations in another area of the interconnection. The second requirement to have these same entities excluding the RC, to always operate the BES to the most limiting parameter. For TOP-003, TOP-005 and TOP-006, we believe a SAR should be initiated to "clean-up" standards & requirements that may be redundant or incorrect as apposed to retiring them within an implementation plan which pertains to a different set of standards.

Response:
EOP-001 R2 - The drafting team believes that load reduction plans are just one of many tools that can be used to resolve IROLs.

IRO-004 R3 – The requirement does not recognize the authority of the Reliability Coordinator, and therefore the drafting team believes that the new requirements in IRO-009 (R1 and R2) are superior. Requirement R3 in IRO-004 gives the Reliability Coordinator an equal position with Transmission Operators and Balancing Authorities in developing action plans. The requirement is ambiguous because it isn't clear which entity has final authority in developing the action plan if the responsible entities can't agree on the best action to take. In addition, the R3 is aimed solely at "transmission loading" – the intent should be to return the bulk power system to within limits – and this may involve moving generation, modifying VAR flows or reserves, or other actions. Note that the standard does require having a plan for every identified IROL as per R1 and R2 of IRO-009-1.

IRO-005 R5 – This requirement is not technically correct – it has multiple tasks embedded in a single requirement, and is written as though the actions should be performed sequentially. First, the Reliability Coordinator may not have the capability of seeing all SOLs**.** Every facility in the Transmission Operator's area has a System Operating Limit, but the Reliability Coordinator isn't required to see all these limits and may not have information to determine the cause of instances of exceeding these limits. When a limit has been exceeded, if it is an IROL, the Reliability Coordinator needs to focus on relieving the limit, and in some cases this is more important than determining what caused the IROL. In the new FAC standards, it is clear that each IROL must have its own IROL Tv – and the Tv may not be longer than 30 minutes – leaving that language in this requirement would directly conflict with the new standard that requires the IROL to be resolved within Tv – not within 30 minutes.

IRO-005 R13 - There was a typographical error in the implementation plan – and this has been corrected. R13 is recommended, as shown in the table and in the red line version of IRO-005 that was posted for review, for revision, not for retirement.

For standards that were initiated prior to Version 0, the Standards Committee has authorized drafting teams to recommend the modification/retirement of requirements in Version 0 standards that are replaced/modified by an associated Version 1 requirement. The reason for this authorization is because the Version 1 drafting teams initiated their SARs before the Version 0 effort was started. Note that the recommended

Organization/Group		Question 7 Comments:
modifications are limited to those associated with requirements that are being replaced or revised as a result of the three remaining new IROL standards. The ballot for the IROL standards will include the recommended retirements and revisions. The IROL SDT limited its recommendations for retirements and revisions to those requirements that were technically incorrect based on the proposed IROL standards or were redundant with requirements in the proposed IROL standards.		
American Transmission Company LLC	No	Issue 1: The implementation plan states that all of IRO-004-1 will be deleted when IRO-008, 009 and 010 are approved. Requirement 7 in IRO-004-1 is not being covered in any of the proposed new standards. The SDT needs to document the justification behind the deletion of R7 in IRO-004-1 before the entire standard can be deleted. Issue 2: ATC does not agree that IRO-005-1 R2 is duplicative of IRO-010-1 R1 and R2. IRO-005-1 R2 requires monitoring but IRO-010-1 R1 and R2 are data specification requirements for study purposes. ATC believes that the RC should be required to monitor Interchange Transactions. Issue 3: Requirement 14 of IRO-005-1: The SDT has proposed to remove the language that requires the RC to provide the TSP with SOL and IROL limits. We were unable to locate any requirements in IRO-008, 009 and 010 that requires the RC to share SOL and IROL limits with the TSP. It should be the obligation of the RC to provide these limits to the TSP. IRO-002-1 R5 and R6 require the RC to monitor SOLs and FAC-014 R1 requires the RC to ensure that SOLs and IROLs are consistent with its SOL Methodology. Issue 4: ATC does not agree with the changes to TOP-005-1. Although TOP-005 Requirement 1 may be a duplicate of IRO-010, TOP-005 obligates that the RC to identify the data requirements for the "Electric System Reliability Data". TOP-005-1 requirements 2 and 3 still address the "Electric System Reliability Data" section so making it a reference document does not remove it from the mandatory realm. In addition, the RC should be required to sign the "NERC Confidentiality Agreement" identified in TOP-005-1 because the TOP, BA and PSE still have to supply the data specified by the "Electric System Reliability Data" requirements. Issue 5: TOP-006-1 R4: ATC does not agree with the Set's changes to R4 in TOP-006-1. We believe that the RC should be required to purchase their own weather forecasting service. Since most utilities purchase weather forecasting services from third party vendors, which have restrictions about sharing that information, this change would require ATC to purchase and maintain a weather forecasting license for our RC. ATC believes that the above statement is true because the SDT is recommending in its implementation plan that the RC would specify in IRO-010 R1 and R2 the required weather forecasting information. If this is not the case then the SDT should provide information as to why the RC is being removed from Requirement 4 in TOP-006-1.
Response: Issue 1: The drafting team agrees and will retain Requirement R7. The drafting team working on the set of real-time standards for the Transmission Operator and Balancing Authority will address the retirement of this requirement. Issue 2: The drafting team did not state that IRO-010 R1 and R2 "duplicate" IRO-005 R2. In addition, the data specification in R1 is for all data that the Reliability Coordinator needs for Real-Time Monitoring, Operational Planning Analyses, and Real-time Assessments– and it is not limited to study purposes.		

Organization/Group		Question 7 Comments:
Having the Reliability Coordinator monitor the Interchange Transactions would be a modification to the existing R2 and isn't necessary - the e-tag system replaced the need for this requirement. If the Reliability Coordinator needs this information, the Reliability Coordinator can add this item to the list of data and information on its data specification under IRO-010 R1. Issue 3: The requirement to provide entities with SOLs and IROLs is addressed in FAC-014, Requirement 5. Issue 4: Most entities agreed with having the Reliability Coordinator develop a data specification that includes all data needed to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. Reference documents do not contain mandatory performance requirements – they may provide information on how to implement a standard, or may explain some aspect of a standard. The drafting team agrees that entities should have to sign the NERC Confidentiality Agreement – but this seems to be a requirement associated with certification rather than in a reliability standard. Issue 5: IRO-010 R1 does not require that the Reliability Coordinator's data specification mandate that entities provide weather forecast data as received from a licensed weather forecasting service. The Reliability Coordinator was removed from TOP-006-2 R4 because the Reliability Coordinator has a requirement to produce a data specification in IRO-010 R1. The SDT is not recommending anywhere that the Reliability Coordinator would specify in IRO-010 R1 and R2 the required weather forecasting information.		
Operating Reliability Working Group	No	The retirement of IRO-004-1, R4 and R5 and replacement by IRO-010-1, R1, R2 and R3 seem to be focused on the front-end data sharing requirements. IRO-004-1, R5 specifically addresses sharing the results of the Reliability Coordinator's studies. We can not find a comparable replacement in IRO-010-1, or elsewhere, for this requirement. The SDT should consider moving IRO-005-2, R13 and R14 since these requirements are no longer directed toward the Reliability Coordinator. They don't fit in the IRO standards. We can't seem to find an entry for the retirement of R7 of IRO-004-1. Attachment 1 to TOP-005-2 is shown in the redline version as being deleted apparently due to the proposed retirement of R1. However, Attachment 1 is also referenced in R3 and therefore should not be deleted.
Response: The implementation plan should have recommended retiring IRO-004 R5 because it is replaced with IRO-008 R3 in combination with IRO-010 R3. The team has corrected the implementation plan. In the next round of edits to these standards, we expect that many requirements will be re-sorted so they are in more logical groupings.		

Organization/Group		Question 7 Comments:
IRO-004-1 R7 - The drafting team agrees that none of the proposed standards addresses this topic and will retain Requirement R7. The drafting team working on the set of real-time standards for the TOP and BA will address the retirement of this requirement. The drafting team returned Attachment 1 to the standard as proposed. It is referenced in R3 as you noted, and will not be deleted by the IROL SDT.		
FirstEnergy	Yes	The effective dates correctly follow the end of the implementation schedule for FAC-014.
Response: Thank you for your support.		
SERC OC Standards Review Group - IROL Standards, IRO-008-1, 009-1, 010-1	Yes	We indicated "Yes" but are really unsure if we are sufficiently aware of what the impacts of the modifications are to system operations. We appreciate the extraordinary amount of effort by individuals involved in developing and revising standards, but we find the implementation plan confusing. This is not the fault of the drafting team, but the fault of the process. There have been innumerable changes to existing standards and to the Functional Model, coupled with FERC requirements to make changes in order to receive their approval. Revisions to standards are being promulgated too rapidly for members to have time to review or keep abreast of proposed changes. The Implementation Plan appears to justify the proposed revisions to, and retirement of, existing standards. we can only trust that the drafting team is using the currently approved version of each identified standard and has stayed abreast of any proposed changes to those standards.
Response: The drafting team is sympathetic – but cannot identify any easy way to manage the number of modifications under development at the same time as we try to comply with the many directives in Order 693 and improve the standards as rapidly as possible. The drafting teams have coordinated their activities to ensure that no critical reliability requirements are dropped, and to ensure that redundant requirements are retired.		
Entergy Services	Yes	
RCCWG - reliability coordinator comments working group	Yes	
San Diego Gas and Electric Co.	Yes	
Manitoba Hydro	Yes	

8. If you have any other comments on this set of standards that you haven't already provided, please provide them here?

Organization/Group	Question 8 Comments:
Northeast Utilities	(1) For IRO-009, the VFRs for R1 and R2 should both be HIGH. The absence of predetermined control actions that need to be made available to operation personnel to prevent and mitigate IROL being exceeded can result in failure to maintain interconnected system reliability. Operating personnel may be faced with having insufficient or no control actions to correct an IROL violation, which can lead to cascade tripping or instability. We believe this comment is consistent with our interpretation of the HIGH risk factor requirement definition (see the text on "planning time frame"): (2) High Risk Requirement A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. (3) We do not understand the distinctions made (under the Compliance Enforcement Authority in the Compliance Monitoring Process of all 3 draft standards) between the RCs that work for the Regional Entity and those that do not. Please provide examples of those RCs that work for an RE. The latter, as a standard developer and compliance monitor per the functional model, does not have any operating and planning tasks assigned to them that require it to employ an RC. However, we do realize that there are REs that are requested by membership in the region through a contractual agreement to perform the RC function for them. In this case, it is the RE that is by contractual arrangement to operate the RC on the membership's behalf, not an employment of an RC by an RE (i.e. an RC working for an RE). If the SDT is referring to this type of set up, please revise the language accordingly.
Response: The drafting team posted the VRFs for IRO-009 when it posted Draft 7 of the standard (January 2 – February 15, 2007) and asked stakeholders if the VRFs were acceptable. At that time, most commenters – including a commenter from Northeast Utilities, indicated support for the "Medium" VRF for both R1 and R2. Having action plans is important – but failure to have an action plan does not, in and of itself, cause bulk power system instability, separation, or a cascading sequence of failures. The intent of the language identifying which entity will serve as the Compliance Enforcement Authority is intended to ensure that no Regional Entity audits an entity that is responsible to that entity. This occurs in WECC, SPP, and FRCC. The language in this section of the standard supports the ERO Rules of Procedure.	
NPCC Regional Standards Committee, RSC	(1) For IRO-009, the VFRs for R1 and R2 should both be HIGH. The absence of predetermined control actions that need to be made available to operation personnel to prevent and mitigate IROL being exceeded can result in failure to maintain interconnected system reliability. Operating personnel may be faced with having insufficient or no control actions to correct an IROL violation, which can lead to cascade tripping or instability. We believe this comment is consistent with our interpretation of the HIGH risk factor requirement definition (see the text on "planning time frame"):High Risk Requirement A

	requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. (2) We do not understand the distinctions made (under the Compliance Enforcement Authority in the Compliance Monitoring Process of all 3 draft standards) between the RCs that work for the Regional Entity and those that do not. Please provide examples of those RCs that work for an RE. The latter, as a standard developer and compliance monitor per the functional model, does not have any operating and planning tasks assigned to them that require it to employ an RC. However, we do realize that there are REs that are requested by membership in the region through a contractual agreement to perform the RC function for them. In this case, it is the RE that is by contractual arrangement to operate the RC on the membership's behalf, not an employment of an RC by an RE (i.e. an RC working for an RE). If the SDT is referring to this type of set up, please revise the language accordingly.
Response: The drafting team posted the VRFs for IRO-009 when it posted Draft 7 of the standard. At that time, most commenters – including commenters from the NPCC CP-9, indicated support for the Medium VRF for R1 and R2. Having action plans is important – but failure to have an action plan does not, in and of itself, cause bulk power system instability, separation, or a cascading sequence of failures. The intent of the language identifying which entity will serve as the Compliance Enforcement Authority is intended to ensure that no Regional Entity audits an entity that is responsible to that entity. This occurs in WECC, SPP, and FRCC. The language in this section of the standard supports the ERO Rules of Procedure.	
Hydro-Quebec TransEnergie	(1) For IRO-009, the VFRs for R1 and R2 should both be HIGH. The absence of predetermined control actions that need to be made available to operation personnel to prevent and mitigate IROL being exceeded can result in failure to maintain interconnected system reliability. Operating personnel may be faced with having insufficient or no control actions to correct an IROL violation, which can lead to cascade tripping or instability. We believe this comment is consistent with our interpretation of the HIGH risk factor requirement definition (see the text on "planning time frame"):High Risk Requirement A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. 2) We do not understand the distinctions made (under the Compliance Enforcement Authority in the Compliance Monitoring Process of all 3 draft standards) between the RCs that work for the Regional Entity and those that do not. Please provide examples of those RCs that work for an RE. The latter, as a standard developer and compliance monitor per the functional model, does not have any operating and planning tasks assigned to them that require it to employ an RC. However, we do realize that there are REs that are requested by membership in the region through a contractual agreement to perform the RC function for them. In this case, it is the RE that is by contractual arrangement to operate the RC on the membership's behalf, not an employment of an RC by an RE (i.e. an RC working for an RE). If the SDT is referring to this type of set up,

	please revise the language accordingly.
Response: The drafting team posted the VRFs for IRO-009 when it posted Draft 7 of the standard. At that time, most commenters – including commenters from the NPCC CP-9 (which included comments from Hydro-Quebec TransEnergie) and comments submitted solely by Hydro-Quebec TransEnergie, indicated support for the Medium VRF for R1 and R2. Having action plans is important – but failure to have an action plan does not, in and of itself, cause bulk power system instability, separation, or a cascading sequence of failures. The intent of the language identifying which entity will serve as the Compliance Enforcement Authority is intended to ensure that no Regional Entity audits an entity that is responsible to that entity. This occurs in WECC, SPP, and FRCC. The language in this section of the standard supports the ERO Rules of Procedure.	
Ontario IESO	(1) For IRO-009, the VFRs for R1 and R2 should both be HIGH. The absence of predetermined control actions that need to be made available to operation personnel to prevent and mitigate IROL being exceeded can result in failure to maintain interconnected system reliability. Operating personnel may be faced with having insufficient or no control actions to correct an IROL violation, which can lead to cascade tripping or instability. We believe this comment is consistent with our interpretation of the HIGH risk factor requirement definition (see the text on "planning time frame"):High Risk Requirement A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. (2) We do not understand the distinctions made (under the Compliance Enforcement Authority in the Compliance Monitoring Process of all 3 draft standards) between the RCs that work for the Regional Entity and those that do not. Please provide examples of those RCs that work for an RE. The latter, as a standard developer and compliance monitor per the functional model, does not have any operating and planning tasks assigned to them that require it to employ an RC. However, we do realize that there are REs that are requested by membership in the region through a contractual agreement to perform the RC function for them. In this case, it is the RE that is by contractual arrangement to operate the RC on the membership's behalf, not an employment of an RC by an RE (i.e. an RC working for an RE). If the SDT is referring to this type of set up, please revise the language accordingly. (3) For R2/M2 of IRO-008, it is not possible to keep records of 30 minute IROL analysis for 30 days. Such time-logged analysis which are probably the only evidence of 30 minute analysis and these can only be located on the security analysis software and we do not believe that such software have the capability of keeping such extended records. We believe that the evidence retention for R2/M2 should be a couple of days at the most. in other words, the previous documentation retention requirement for this requirement should be retained.
Response: The drafting team posted the VRFs for IRO-009 when it posted Draft 7 of the standard. At that time, most commenters – including commenters from the NPCC CP-9 (which included comments from IESO) and comments submitted by the IRC Standards Review Committee (which included comments from IESO) indicated support for the Medium VRF for R1 and R2. Comments submitted solely by IESO did recommend that the VRFs for R1 and R2 should both be "high" – but most commenters supported the "Medium" VRFs and the drafting team's reasoning for recommending the "Medium" VRF - Having action plans is important – but failure to have an action plan does not, in and of itself, cause bulk power system instability, separation, or a cascading sequence of failures.	

The intent of the language identifying which entity will serve as the Compliance Enforcement Authority is intended to ensure that no Regional Entity audits an entity that is responsible to that entity. This occurs in WECC, SPP, and FRCC. The language in this section of the standard supports the ERO Rules of Procedure. The evidence required for R2/M2 doesn't have to be the security analysis software – the measure allows for a variety of evidence – one of the types of acceptable evidence is an audit log or a checklist to verify that the analysis was conducted.	
ISO RTO Council Standards Review Committee	(1) For IRO-009, the VRFs for R1 and R2 should both be HIGH. The absence of predetermined control actions that need to be made available to operation personnel to prevent and mitigate IROL being exceeded can result in failure to maintain interconnected system reliability. Operating personnel may be faced with having insufficient or no control actions to correct an IROL violation, which can lead to cascade tripping or instability. We believe this comment is consistent with our interpretation of the HIGH risk factor requirement definition (see the text on "planning time frame"):High Risk Requirement A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. (2) We do not understand the distinctions made (under the Compliance Enforcement Authority in the Compliance Monitoring Process of all 3 draft standards) between the RCs that work for the Regional Entity and those that do not. Please provide examples of those RCs that work for an RE. The latter, as a standard developer and compliance monitor per the functional model, does not have any operating and planning tasks assigned to them that require it to employ an RC. However, we do realize that there are REs that are requested by membership in the region through a contractual agreement to perform the RC function for them. In this case, it is the RE that is by contractual arrangement to operate the RC on the membership's behalf, not an employment of an RC by an RE (i.e. an RC working for an RE). If the SDT is referring to this type of set up, please revise the language accordingly.
Response: The drafting team posted the VRFs for IRO-009 when it posted Draft 7 of the standard. At that time, most commenters – including commenters from the IRC Standards Review Committee indicated support for the Medium VRFs for R1 and R2. Having action plans is important – but failure to have an action plan does not, in and of itself, cause bulk power system instability, separation, or a cascading sequence of failures. The intent of the language identifying which entity will serve as the Compliance Enforcement Authority is intended to ensure that no Regional Entity audits an entity that is responsible to that entity. This occurs in WECC, SPP, and FRCC. The language in this section of the standard supports the ERO Rules of Procedure.	
RCCWG - reliability coordinator comments working group	RSAWS need to be developed in parallel with standard revisions to they maintain the intention of the standard for the audit team.
Response: The drafting team's scope does not include development of Reliability Standard Audit Worksheets (RSAWs). The group that develops RSAWs has access to the standard for use in developing RSAWs.	

Manitoba Hydro	There needs to be coordination between IRO-010-1, TOP-005-0 Attachment 1, and VAR-002-1. Is it the intention of IRO-010-1 to ensure the RC has real-time data to monitor the state of the bulk electric system? TOP-005-0 Attachment 1 which is to become a Technical Reference states "1. The following information shall be updated at least every 10 minutes." VAR-002-1 R3 states "Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability. R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability." This does not give the impression that real time status is required. For BES reliability, we ultimately think there should be real-time status from the AVR, PSS or SPS into the entity's Control Centre EMS and simultaneously through an ICCP link to the RC EMS. This approach would be the most robust with the least amount of chance of a communication break down attributed to human error. For an entity with over 100 generators, a project to bring real time AVR, PSS and SPS status into the Control Centre EMS and transfer the data via ICCP to the RC EMS would be very time consuming and costly. We would suggest a period of grace (dependent on number of RTU points required (up to several years)) for entities to reach this goal. During this grace period we suggest that knowledge of AVR, PSS, and SPS status by default is sufficient. In other words the device is considered "in service/on auto" unless the system operator is notified differently. The system operator manually toggles into SCADA the status of the device. The device's status change is communicated to the RC "without delay" either electronically or verbally. The device status in the RC EMS would be updated at this time. Both the entity's and the RC's EMS Real Time Contingency Analyses would be utilizing the latest known AVR, PSS and SPS status. As I see it, this approach, if agreed to by the RC, would satisfy IRO-010-1 R1 - R1.3 and R1 Violation Severity Levels "Lower" through to "Severe".
Response: The drafting team is not recommending that VAR-002 R1 should be retired and is no longer recommending the retirement of TOP-005 Attachment 1. VAR-002-1 R3 requires the Generator Operator to provide specific information to the Transmission Operator – not the Reliability Coordinator.	
Operating Reliability Working Group	The Applicability section of IRO-009-1 includes more than a list of entities to which the standard applies. In this situation, a 'what' the standard applies to be included. We've never seen this before and question it's applicability in this case. Add parenthesis around the phrase 'up to and including load shedding' in R1 of IRO-009-1. The same phrase already exists in R2 in parenthesis. In the Compliance Section D, Item 1.4 Data Retention of IRO-010-1 the third paragraph states that the BA, GO, GOP, LSE, RC, TOP and TO shall keep evidence used to show compliance with R3 and M3. How much evidence is required? Prior versions of IRO-010 indicated that 3 months of evidence would be sufficient. Not including a specific reference leaves the

	standard vague. A specific reference should be included. We suggest returning to the 3 month requirement. Also in this same Item 1.4 the phrase "in advance of real-time" shows up. If it was replaced in IRO-009-1, it should also be replaced here as well.
Response: The Applicability Section of the standard may include any information that describes limits on the applicable entities or facilities. The drafting team reviewed the inclusion of the qualifying language and determined that it did not add anything significant to the standard and deleted this. The drafting team adopted your suggestion and added parentheses as proposed to IRO-009 R1. The drafting team added "90 days" as the outside parameter for data retention for R3 M3. The drafting team modified the data retention to include the following phrase, " in accordance with Requirement R2" in support of the intent of your suggestion.	
SERC OC Standards Review Group - IROL Standards, IRO-008-1, 009-1, 010-1	We feel that the Implementation Plan should not set different implementation dates for jurisdictional and non-jurisdictional entities. This puts an additional burden on Reliability Coordinators to resolve problems involving entities subject to different standards. Our recommendation is that the standard should become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval. One concern certain members have involves data retention requirements for IRO-10-1 at R3 and M3 when a system is part of an ISO or RTO and is required by its Reliability Coordinator to input its data into the ISO or RTO business system. For instance, a Reliability Coordinator may require generator operators to periodically update generator operating limits in support of R1-R3 citing two (2) horizons for such entries: (1) the day prior to the operating day and (2) as changes occur in real time. Members agree with the requirements, however data is manually entered into the business system and the member does not have the ability to retain the data or verify that it was entered. Given that the requirements call for the Reliability Coordinator to be provided the data, the measures should require that the RC retain the data provided.
Response: There are numerous regulatory authorities that need to approve these standards – every Canadian province in Canada – and FERC in the USA. All of the SERC entities are within the USA and are required to comply with standards that are approved by FERC. The compliance program is set up to require the responsible entity to demonstrate that it is compliant. Note that the measure allows the responsible entity great latitude in demonstrating that data was provided. For example, the responsible entity could ask the Reliability Coordinator to provide a letter confirming that it had received the data from the Generator Operator – and the Generator Operator could make this letter available as a method of demonstrating compliance. The measures were changed so that they now say that evidence must be "made available" rather than evidence must "be provided".	
FirstEnergy	FE has the following additional comments and suggestions: (1) IRO-010 - Requirement R1 - Remove the word "data" between documented and specification to improve clarity and readability.

	(2) The last sentence of R3 contains a phrase that was previously proposed to be a new term in IRO-007-1, but is now being deleted. If this intended to be retained as a new definitional term within the Glossary it will need to be added to IRO-010. When revised R1.1 and R3 should read as follows: (3) IRO-010 - Presumably the last sentence of R3 is designed to limit the data that the Reliability Coordinator may request from the various responsible entities listed. However, in its current state, the requirement seems to limit what the affected entities can provide. We suggest that it may be clearer to remove the last sentence of R3 and append it to the existing R1.1 requirement. The new R1.1 and R3 are proposed as follows:"R1.1. List of required data and information. The data and information is limited to data needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments.""R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified by R1 above, to the Reliability Coordinator(s) with which it has a reliability relationship." (4) With regard to Attachment 1 of TOP-005-2, this information in this attachment is to be transferred to a "Reference" document. However, it is not clear when this reference document is to be developed since a draft of this proposed reference is not available for comment. We suggest this reference document be developed and posted along with these new IROL standards so that it is all completed at the same time. The reference document will be a valuable tool to be used in conjunction with the standards and should be developed in conjunction with these standards. (4) In some of the revised standards, references to previous IROL requirements have been removed as they are now covered in the proposed IRO standards. In some cases, these revisions have led to entire requirements being deleted. It is brought to the attention of the SDT that requirement re-numbering was not correctly shown in the red-line standards provided for review and will need to be corrected in final changes. (e.g. EOP-001, TOP-005, etc.) (6) In IRO-009-1 the Applicability section contains 4.2 stating "The IROLs covered in this standard are limited to those associated with contingencies studied under FAC-011 and FAC-014." The NERC Standard Development Procedure indicates that the Applicability Section is intended to describe the 1) entities responsible for complying with the standard and 2) if needed, the portion of the bulk power system for which the standard is applicable. The 4.2 item may introduce an unintended use of the Applicability section and it may be better to move this item to a new requirement R1 in the standard worded as follows:"R1 Each Reliability Coordinator shall manage its current day system against IROL conditions identified in a manner consistent with the requirements of standards FAC-011 and FAC-014."
Response: **1 –** The drafting team removed the extra word, "data" from IRO-010 - Requirement R1 as proposed. **2 –** The drafting team changed the phrase in IRO-010 R1 so that the word, "Monitoring" is no longer capitalized. Note that "Real-time" is a defined term and the drafting team retained the capitalization of this term. 3 **–** IRO-010 R1.1 and R3 - The drafting team moved the sentence from R3 to R1.1 as suggested. 4 **–** The IROL drafting team has removed its recommendation to retire Attachment 1 in TOP-005-2 because the attachment is referenced in Requirement 3 in TOP-005-2 which is not being retired by the IROL drafting team. There is another team that is recommending that TOP-005-2 R3 be retired or revised and that drafting team may recommend retirement of Attachment 1.	

5 **–** Red line renumbering - Agree – red line numbering doesn't always work because of the auto features in Word. 6 - The drafting team removed 4.2 from the revised standard.	
Hydro One Networks	We believe a SAR should be initiated to "clean-up" standards & requirements that may be redundant or incorrect as apposed to retiring them within an implementation plan which pertains to a different set of standards. As well, for IRO-009, the VRFs for R1 and R2 should both be High.
Response: For standards that were initiated prior to Version 0, the Standards Committee has authorized drafting teams to recommend the modification/retirement of requirements in Version 0 standards that are replaced/modified by an associated Version 1 requirement. The reason for this authorization is because the Version 1 drafting teams initiated their SARs before the Version 0 effort was started. Note that the recommended modifications are limited to those associated with requirements that are being replaced or revised as a result of the three remaining new IROL standards. The ballot for the IROL standards will include the recommended retirements and revisions. The IROL SDT limited its recommendations for retirements and revisions to those requirements that were technically incorrect based on the proposed IROL standards or were redundant with requirements in the proposed IROL standards. The drafting team posted the VRFs for IRO-009 when it posted Draft 7 of the standard (January 2 – February 15, 2007) and asked stakeholders if the VRFs were acceptable. At that time, most commenters including a commenter from Hydro One Networks who submitted comments as part of the NPCC CP9 Reliability Standards Working Group indicated support for the "Medium" VRF for both R1 and R2. Having action plans is important – but failure to have an action plan does not, in and of itself, cause bulk power system instability, separation, or a cascading sequence of failures.	
American Transmission Company LLC	Operational Planning Analysis (Definition): The phrase "next day's operation and up to 12 months ahead" (See definition of Operational Planning Analysis) is too broad when used in the context of requirement 1. The definition should be broken into two independent definitions one to address the "next day study" and a second to address the "up to 12 months study". Requirement 1 states that the RC has to perform an Operational Planning Analysis which, we have identified above, means "next day and up to 12 months" for the next operating day. By including the "up to 12 months" in the definition we believe that for every next day study the RC has to perform two independent studies. 1) One for the next day and 2) One for some other day that is up to 12 months It is for this reason that we suggest that the definition be broken into two distinct terms. IRO-008-1: ATC believe that IRO-008-1 R1 and R2 should be expanded to include SOLs in the Operational Planning Analysis and Real-Time Assessment. IRO-009-1The applicability section of that standard is to be used to identify the functional entity that must comply with the standard. The SDT is using this section to place an exception on the requirements. Any exception should be identified in the requirements. (Solution could be with a footnote) Standard IRO-009-1 needs two additional requirements: 1) Require the RC has to coordinate their plans with entities that are expected to perform an action in the plan. 2) Distribute and share those plans with entities that are expected to perform an action. R3 ATC is concern that compliance is based on following the plan and what is more important is if the RC prevented the IROL from exceeding the Tv. The requirement should specify that the RC prevents the IROL not that they follow their plan. IRO-010-1 Data Retention rule A more specific data retention period should be established. The current language would

	require ATC to keep data anywhere from one month to seven years or more. "For data that is requested in advance of real-time the TOP shall keep evidence used to show compliance with R3 for the RC's most recent data specifications." (If the RC updated their data specifications once every seven years all entities must retain their data for seven years.) General Comment: ATC suggest that this SDT work closely with the Reliability Coordinator SDT in order to ensure a comprehensive set of standards.

Response:

Definition of Operational Planning Analysis **-** The drafting team modified the definition to clarify that there needs to be an analysis for each day, but the analysis does not need to be done once a day – and the analysis does not have to look at every day from the next day up to a year ahead.

Expansion of IRO-008-1 R1 and R2 to include SOLs - The drafting team did not adopt this suggestion. The Reliability Coordinator may not have the ability to see all SOLs. This set of standards has focused on those SOLs that have greatest impact on the bulk electric system – the IROLs. The RTO SDT is working on specific requirements related to SOLs that are not IROLs.

IRO-009-1 Applicability Section - The drafting team removed 4.2 from the Applicability Section of the standard because it duplicates information already included in the requirements. Note that the applicability section of the standard can also be used to identify other limitations on the applicability of the standard – such as limiting applicability to a specific type of facility or to a specific geographic location, etc.

Standard IRO-009-1 – proposal to add requirements for the Reliability Coordinator to "coordinate" and "distribute" its plans - The drafting team did not adopt this suggestion. Under IRO-008, the Reliability Coordinator has to share the results of its analyses and assessments if they indicate the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL. IRO-009 requires the Reliability Coordinator to direct entities to follow specific action plans to prevent/mitigate instances of exceeding IROLs. The Reliability Coordinator is responsible for acting or directing others to act – the word, "coordination" doesn't convey the same meaning.

The drafting team added a phrase to R3 to clarify that the Operating Processes, Procedures and Plans used to prevent exceeding an IROL are not limited to those identified in R1 but did not modify the requirement to change the emphasis- the drafting team thinks that it will not always be possible to prevent exceeding an IROL.

IRO-010-1 Data Retention - The drafting team added "for a rolling 90 days" to the data retention requirement for R3.

The drafting team is working closely with the Reliability Coordination SDT to ensure coordination.

Observations and Discussions with FERC Staff May 29, 2008 and June 3, 2008

The following notes were developed from a combination of two conference calls conducted on May 29, 2008 and on June 3, 2008 with members of FERC Staff, members of the IROL Standard Drafting Team, and members of NERC's staff. There were no formal agendas for the meetings, but the purpose was to review the FERC directives from Order 693 applicable to the IROL Standards and identify any areas where FERC staff had concerns about meeting the directives.

The following people were in attendance during the call on May 29, 2008:

IROL Standard Drafting Team:
- Ellis Rankin, chair
- Jim Case
- Al DiCaprio
- Mike Hardy
- Steve Myers

FERC Staff:
- Keith O'Neal
- Bob Snow

NERC Staff:
- Gerry Adamski
- Maureen Long
- David Taylor

The following people were in attendance during the call on June 3, 2008:

IROL Standard Drafting Team:
- Ellis Rankin, chair
- Jim Case
- Al DiCaprio
- Mike Hardy
- Tony Jankowski
- Seamus McGovern
- Al Miller
- Jamie Murphy
- Steve Myers

FERC Staff:
- Bob Snow

NERC Staff:
- Maureen Long

There were nine issues discussed during the two conference calls:

Issue 1 – Vetting a drafting team's products against FERC directives

Issue 2 - Reliability-related impact of removing "monitoring SOL" requirements

Issue 3 - Acceptable uses of firm load shedding

Issue 4 – Intent of IRO-010 – R1

Issue 5 - Reliability-related impact of removing Attachment 1 from TOP-005

Issue 6 - Advance notice of planned outages

Issue 7 – Reliability Coordinator tools

Issue 8 - Providing operators with action plans for n-1-1 conditions

Issue 9 – Reliability-related impact of retiring EOP-001 R2

Issue 1 – Vetting a drafting team's products against FERC directives

FERC: What is NERC process for vetting SDT products against applicable FERC Order Directives and how is the result documented or indicated in public NERC postings?

Discussion: The IROL SDT has not posted its SDT products against the FERC directives, but did conduct a review amongst the SDT members to verify that their work would meet the directives. Does the SDT want to post a table showing the directives & how it met the directives when its posts its work for pre-ballot review?

SDT Resolution: This document is not needed. When the IROL documents are submitted to the Standards Committee for approval to move forward, the Standards Committee should be asked if it wants a list of the FERC directives and the team's consideration of those directives posted for review.

Issue 2 - Reliability-related impact of removing "monitoring SOL" requirements

FERC: SOLs have been removed – focus is on IROLs only – what happened to SOLs?

Make sure the filing identifies what happened to activities that were there before – where are they now, identify where they went – need to show that the 'check and balance' is still there. Identify how the requirements address the time spectrum.

Discussion: How should SDT indicate that SOLs are still to be monitored etc with an appropriate 'oversight' role for RC and what timing implications need to be addressed between IROL standard effective date vs other still pending standards? IE FERC's concern that revised or new standards coordinate etc with current FERC approved standards and do not lead to less reliable BES.

Note - FERC staff looked at the latest posted version of the Implementation Plan – which still recommended retirement of requirements for the RC to "monitor". Because we decided not to include any new requirements for monitoring, our latest version of the implementation plan does not include recommendations to retire the monitoring requirements.

SDT Resolution: No adjustments are needed to the standards or to the implementation plan. Use the advice when filing the standards for approval with regulatory authorities.

Issue 3 - Acceptable uses of firm load shedding

FERC: Look at the transmission themes section of Order 693 – expectation is that load can be served when there are no contingencies on the system –

If you have a single contingency (whatever equipment taken out of service – the protective zone of the fault is a single contingency) there can be some consequential load loss

Discussion: Clarify the use of Firm Load Shed action as part of any operating time frame emergency plan (and not as a substitute for utilization of all physical resources available within the time frame).

SDT Resolution: No adjustments are needed to the standards or to the implementation plan. Document the team's approach when filing the standards for approval with regulatory authorities.

Issue 4 – Intent of IRO-010 – R1

FERC: IRO-010 – Requirement R1 **-** Consider moving the purpose statement into the requirement

Discussion: The drafting team agreed that the proposed modification would clarify the intent of R1.

SDT Resolution: Modify IRO-010 R1 to add key words from the purpose to the requirement to clarify the intent of the requirement.

Issue 5 - Reliability-related impact of removing Attachment 1 from TOP-005

FERC: The Implementation plan states that the list of data will be moved into a tech reference – but there is no tech reference posted . . .

What is the advantage of moving the attachment into a reference – does this result in a better standard than you would achieve if the attachment were a set of "minimums" that must be met?

Discussion: We need some key words we can use when we file this standard for regulatory approval to show that we haven't degraded reliability by requiring the Reliability Coordinator to have a data specification. The team felt that having a set of minimum elements to address would allow some entities to default into a position of thinking that these are the only elements that need to be addressed – and felt that forcing the Reliability Coordinator to document what it needs would result in a better product.

SDT Resolution: One of the stakeholder comments submitted during the public posting period identified that the attachment is referenced in TOP-005 Requirement R3 (that requirement is not being retired by the IROL SDT) and the attachment needs to be retained. The drafting team modified its Implementation Plan so that it no longer recommends retirement of Attachment 1 in TOP-005.

Issue 6 - Advance notice of planned outages

FERC: Consideration of Order 693 Paragraph 1621 regarding planned outage lead times isn't reflected in the implementation plan's recommendation to revise TOP-003 R1

The change proposed for TOP-003 R1 is:

> **R1.** Generator Operators and Transmission Operators shall provide planned outage information.
>
> > **R1.1** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.
> >
> > **R1.2** Each Transmission Operator shall provide outage information daily to ~~its Reliability Coordinator, and to~~ affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. ~~The Reliability Coordinator shall establish the outage reporting requirements.~~

Directives in Order 693 relative to TOP-003:

1. Include a new requirement to communicate longer term outages well in advance to ensure reliability and accuracy of ATC calculation
2. Make any facility below the voltage thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System, subject to Requirement R1 for planned outage coordination
3. Incorporate an appropriate lead time for planned outages as discussed above.

Some of the discussion in Order 693 for TOP-003:

> 1620. In Order No. 890, the Commission directed that information concerning ATC calculations be consistent and transparent. The timing of facility outages is one important piece of information in ATC calculations. In Order No. 890, the Commission directed that specific data be exchanged among transmission providers, including transmission planned and contingency outages, for the purpose of ATC modeling.
>
> Consistent with this determination in Order No. 890, the Commission directs the ERO to develop a modification to TOP-003-0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations. We believe this addresses LPPC's concern regarding the interplay between reliability and business practices.
>
> 1621. Several commenters raised concerns regarding the Commission's proposal to require outage information well in advance. Specifically, they argue that the term "well in advance" is vague, that the requirement would reduce flexibility and that it would cause entities to postpone needed maintenance work, thereby reducing reliability. In response to the Commission's request for comments on lead time for planned outages, entities provide information on current lead time practices indicating that lead times range from one week to 45 days. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages. The ERO should utilize the information filed by commenters in the Reliability Standards development process. In doing so the ERO should take into consideration the need for flexibility, as well the lead time required for coordination with other entities and outage assessments. Proper coordination will ensure that priority is given to needed maintenance work for critical facilities to ensure reliability.

Discussion: There are three FERC directives, the first one applies to the ATC standards – and seems to be addressed in the proposed ATC standards in the requirements for calculating TTC, ATC, and AFC. The second directive should be addressed by the Real-time BA/TOP SDT and the third directive should be addressed in our data spec requirement. Should we consider adding some language to the tech reference to indicate that the RC should request that the TOP/GO/GOP provide outage data as soon as it is known so the RC can incorporate this data in its Operational Planning Analyses?

R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R3.1. For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

R3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

R3.1.2. Load forecast for the applicable period being calculated.

R3.1.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R3.2. For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

R3.2.1. Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

R3.2.2. Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

R3.2.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

The latest draft of MOD-030 includes the following:

R5. When calculating AFCs, the Transmission Service Provider shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R5.1. Use the models provided by the Transmission Operator.

R5.2. Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the period calculated for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

R5.3. For external Flowgates, identified in R2.1.3, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

Note that the third standard for calculating ATC, MOD-029 doesn't have references to outages.

SDT Resolution: No adjustments are needed to the standards or to the implementation plan.

NERC staff will ask the Certification Subcommittee to add the following to the certification process:

- Require the prospective Reliability Coordinator to have a procedure for coordination of planned generation and transmission outages that includes the following:
    - Identification of a lead time for planned outages that provides sufficient time for reliability-related coordination
    - Identification of the criteria used to determine which outages to approve when there are multiple requests for outages and they can't all be approved

Issue 7 – Reliability Coordinator tools

FERC: If the drafting team is expecting that Order 693 Paragraph 1660 regarding minimum tools for the Reliability Coordinator will be addressed through the certification process, the filing for the standard should indicate that the alternate is providing an "equally effective and efficient" method of meeting this directive.

Discussion: Should the IROL standards (or any other standard) specify any minimum tool requirements? The SDT wrote the standards with the expectation that facility requirements would be addressed in certification.

FERC staff looked at the latest posted version of the Implementation Plan – which still recommended retirement of requirements for the RC to "monitor". Because we decided not to include any new requirements for monitoring, our latest version of the implementation plan does not include recommendations to retire the monitoring requirements.

SDT Resolution: No adjustments are needed to the standards or to the implementation plan. The drafting team's set of standards do not include any for "monitoring" – and the implementation plan does not recommend retirement of any "monitoring" requirements.

Issue 8 - Providing operators with action plans for n-1-1 conditions

FERC: Review paragraph 1601 in the Order – this suggests that if the next evil thing occurs before the system is returned to a stable state, then there should be a pre-defined plan in place for the system operator to use. This should include a plan for every possible second contingency and should include control actions.

1601. . . .Therefore, we direct the ERO to modify Reliability Standard TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.

Clarification: FERC staff advised that this paragraph requires that the system operator be provided with action plans to use to prepare for the next contingency during the adjustment time period when an IROL has been exceeded but the system hasn't been returned to a "stable" or "normal" state.

Discussion: None of the drafting team members participating in the call agreed with this interpretation of Paragraph 1601.

SDT Resolution: No adjustments are needed to the standards or to the implementation plan. Document the team's understanding of 1601 when filing the standards for approval with regulatory authorities.

Issue 9 – Reliability-related impact of retiring EOP-001 R2

FERC: The drafting team needs to verify that when EOP-001 R2 is retired, there is still a requirement for the TOP to have load reduction plans that can be executed within a specific time frame – otherwise, the drafting team should consider whether the retirement of EOP-001 R2 could result in less reliability.

Discussion: The drafting team is recommending that EOP-001 R2 be retired when IRO-009-1 R1 and R2 become effective. The RC, not the TOP is responsible for developing plans to prevent and mitigate instances of exceeding identified IROLs. Mitigation plans need to be implemented so that the instance of exceeding the IROL is mitigated within the IROL's T_v, which can be shorter than 30 minutes.

EOP-001 R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

SDT Resolution: EOP-001 R3 and R4 require the TOP to have load reduction plans that can be executed within a specific timeframe – so the recommended retirement will not adversely impact reliability, and no change was made to the implementation plan.

EOP-001

R3. Each Transmission Operator and Balancing Authority shall:

- **R3.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.
- **R3.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
- **R3.3.** Develop, maintain, and implement a set of plans for load shedding.
- **R3.4**. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

- **R4.1.** Communications protocols to be used during emergencies.
- **R4.2.** A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.