Individual or group. (37 Responses)
Name (22 Responses)
Organization (22 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Question 1 (32 Responses)
Question 1 Comments (37 Responses)
Question 2 (34 Responses)
Question 2 Comments (37 Responses)
Question 3 (21 Responses)
Question 3 Comments (37 Responses)
Question 4 (31 Responses)
Question 4 Comments (37 Responses)
Question 5 (29 Responses)
Question 5 Comments (37 Responses)
Question 6 (33 Responses)
Question 6 Comments (37 Responses)

-
Individual
Scott McGough
Oglethorpe Power Corporation
No
Yes
Group
Bonneville Power Administration
Denise Koehn
Yes
Yes
No preference, we report identified WECC rated paths.
Yes
Yes
No preference.
Yes
Some suggestions: TOP-002-3 1) R1. Remove "and potential Contingency events". Any event could temporarily increase flows over the SOL (or IROL) or cause the SOL to decrease until the flows are mitigated per ROP-001. The system studies set the SOL's to protect the system for such events. The mitigation is then required in TOP-001-2 then (and TOP-004 if it is kept). 2) R1. Reword R1 similar to that of R2 in that TOP "plans" to preclude operating in excess of any SOLs for anticipated normal conditions. This is normal operational planning. All entities should not be planning to exceed SOL for normal conditions. Rewording: R1. "The Transmission Operator shall plan next day's operation to preclude operating in excess of any System Operating Limits (SOLs) during anticipated normal conditions."
Group
Project 2007-02 Operating Personnel Comm Protocols SDT
Harry Tom

Yes
The Operating Personnel Communication Protocols standard drafting team respectfully requests that the Real Time Operations team incorporate the following into your proposed TOP-001: “Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have procedures for the communication of information concerning the transmission emergency alerts in accordance with the conditions described in Attachment 1 Transmission Emergency Alerts .” In addition, the Applicability Section 4 would need to include Reliability Coordinators. The Operating Personnel Communications Protocols Project 2007-02 was initiated to ensure that real time system operators use standardized communication protocols during normal and emergency operations to improve situational awareness and shorten response time. The SDT developed a new COM-003-1 Standard that has yet to be posted and is dependent upon revising at least two other standards (CIP-001 and appropriate TOP Standard). COM-003 contains requirements that specify: 1. Use of three-part communication; 2. English language; 3. Common time zone; 4. NATO alpha-numeric alphabet; 5. Mutually agreed line identifiers; 6. The use of pre-defined system condition terminology such as those contained in the RCWG Alert Level Guide and EOP-002-2. This request is based on recent NERC Standards Committee direction to our team to incorporate the Reliability Coordinator Working Group’s (RCWG) Alert Level Guide into a Standard. The consensus of our team is that a TOP Standard is the most appropriate location for the Transmission Emergency Alert language from the Guide as the energy emergency alert language is currently described in EOP-002-2. The RCWG Guide proposes the use of pre-defined system condition descriptions for use during emergencies for reliability related information. This guide was developed in response to a Blackout Report recommendation. Our team placed the energy cyber and physical security emergency alert language into CIP-001. Since the Real Time Operations SDT is currently modifying TOP-001 through 004, we seek your consent to incorporate the transmission emergency alert language to comply with the wishes of the Standards Committee. We believe that a TOP Standard is the most appropriate location for this language for the following reasons: • The levels of emergency conditions related to the transmission system is based upon maintaining the transmission system within Interconnection Reliability Operating Limits. • Your proposed TOP-001 R2 already requires the sharing of information of actual and anticipated transmission emergency conditions and the use of pre-defined terminology supports the efficient sharing of such information. The following text is appended here for the record. It is the OPCP SDT proposal for a revised TOP Standard that incorporates the TEA material. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 1 of 17 Effective Date: October 1, 2007 A. Introduction 1. Title: Transmission Operations 2. Number: TOP-004-3 3. Purpose: To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies; and to communicate transmission emergency alerts. 4. Applicability: 4.1. Reliability Coordinator 4.2. Balancing Authority 4.3. Transmission Operators 5. Proposed Effective Date: First day of first calendar quarter, one calendar year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter a year from the date of Board of Trustee adoption. B. Requirements R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs). R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator. R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area. R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows. R6.2. Switching transmission elements. R6.3. Planned outages of transmission elements. R6.4. Responding to IROL and SOL violations. R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have procedures for the communication of information concerning the transmission emergency alerts in accordance with the conditions described in Attachment 1-TOP-004-3. C. Measures Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 2 of 17 Effective Date: October 1, 2007 M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4. M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6. M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator shall have

and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirement 7. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 3 of 17 Effective Date: October 1, 2007 D. Compliance 1. Compliance Monitoring Process 1.1. Compliance Monitoring Responsibility Regional Reliability Organizations shall be responsible for compliance monitoring. 1.2. Compliance Monitoring and Reset Time Frame One or more of the following methods will be used to assess compliance: - Self-certification (Conducted annually with submission according to schedule.) - Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.) - Periodic Audit (Conducted once every three years according to schedule.) - Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.) The Performance-Reset Period shall be 12 months from the last finding of non-compliance. 1.3. Data Retention Each Transmission Operator shall keep 90 days of historical data for Measure 1. Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2. If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer. Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor, The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data 1.4. Additional Compliance Information None. 2. Levels of Non-Compliance: 2.1. Level 1: Not applicable. 2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4. 2.3. .Level 3: Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 4 of 17 Effective Date: October 1, 2007 2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation: 2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4. 2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4. E. Regional Differences None identified. Version History Version Date Action Change Tracking 0 April 1, 2005 Effective Date New 0 August 8, 2005 Removed "Proposed" from Effective Date Errata 1 November 1, 2006 Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006 Revised 2 December 19, 2007 Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance) Revised Errata Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 5 of 17 Effective Date: October 1, 2007 Attachment 1-TOP-004-3 Transmission Emergency Alert (TEA) Levels Introduction This Attachment provides the procedures by which a Transmission Operator or Reliability Coordinator can advise of actions taken to manage potential or actual Interconnected Reliability Operating Limit (IROL) violations. All three operating alert states (EEAs, TEAs and SEAs) are independent of each other and should be declared independently but they may also be declared concurrently. A. General Requirements 1. Initiation by Reliability Coordinator. A Transmission Emergency Alert (TEA) may be initiated only by a Reliability Coordinator at: 1) the Reliability Coordinator's own request, or 2) upon the request of a Transmission Operator 1.1. Situations for initiating alert. A Transmission Emergency Alert may be initiated for the following reasons: • When all the available generation resources (would also include dispatchable load facilities that dispatch similar to generators on an economic basis) have been committed to respect an IROL in the pre-contingency state or; • When load curtailment procedures have been implemented to respect an IROL. 2. Notification. A Reliability Coordinator who declares a Transmission Emergency Alert shall notify all Transmission Operators and Balancing Authorities in its Reliability Area. The Reliability Coordinator shall also notify Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS) using the "System Emergency" category. Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify all Transmission Operators and Balancing Authorities in its Reliability Area and Reliability Coordinators when the alert has ended. B. Transmission Emergency Alert Levels Introduction Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 6 of 17 Effective Date: October 1, 2007 To ensure that all Reliability Coordinators clearly understand potential and actual actions taken to manage IROLs on the Interconnection, NERC has established three levels of Transmission Alerts. The Reliability Coordinators will use these terms when explaining actions taken to manage IROLs to each other. A Transmission Emergency Alert is an emergency communication protocol , not a daily operating practice, and is not an alternative to compliance with NERC reliability standards. The Reliability Coordinator may declare whatever alert level is appropriate, and need not proceed through the alerts sequentially. 1. Transmission Emergency Alert 1 (TEA 1) – All available generation resources committed to respecting IROLs. Circumstances: • The Reliability Coordinator or Transmission Operator foresees or is experiencing conditions where all available generation resources are committed to respect the IROL and/or is concerned about its ability to respect the IROL. 2. Transmission Emergency Alert 2 (TEA 2) — Load management procedures in effect to respect IROLs. Circumstances: • The Reliability Coordinator or Transmission Operator foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to: • Public appeals to reduce demand. • Voltage reduction. • Interruption of non-firm end use loads in accordance with applicable contracts (for emergency purposes, not economic reasons) • Demand-side management. • Utility load conservation measures • TLR 6 Note: TLR 5 would normally be implemented in advance of this alert state. Under some circumstances TLRs may not be available or effective and would not be called prior to this alert state. During TEA 2, Reliability Coordinators and Transmission

Operators have the following responsibilities: 2.1 Declaration period. The declaring Reliability Coordinator shall update the RCIS under “System Emergency” at a minimum of every hour until the TEA 2 is terminated. 2.2 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may be contributing to the alert level. Where appropriate, the Reliability Coordinators shall inform the Transmission Operators Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 7 of 17 Effective Date: October 1, 2007 under their purview of the pending Transmission Emergency Alert and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures and redispatching generation. The following additional actions should also be considered where appropriate: • Notification of ATC adjustments. Resulting increases in ATCs shall be communicated to the market via posting on the appropriate OASIS websites by the Transmission Providers. • Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the declaring Reliability Coordinator. • Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the declaring entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators. • Initiating inquiries on re-evaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of re-evaluating and revising SOLs or IROLs. 2.3 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses. 2.4 Actions Prior to Declaration of TEA 3. Before declaring a TEA 3, all available generation resources must be committed. This includes but is not limited to: • All available generation units are on-line. All generation capable of being on-line in the time frame of the emergency is on-line including quick-start and peaking units, regardless of cost. • Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost. • Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 8 of 17 Effective Date: October 1, 2007 • Operating Reserves. Operating reserves are being utilized such that the declaring entity may be carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program. 3. Transmission Emergency Alert 3 (TEA 3) — Firm load curtailment in effect to respect IROLs. Circumstances: The Reliability Coordinator or Transmission Operator foresees or has implemented firm load obligation interruption to respect an IROL. 3.1 Continue actions from TEA 2. The Reliability Coordinators and the declaring entity shall continue to take all actions initiated during TEA 2. 3.2 Declaration Period. The declaring Reliability Coordinator shall update the RCIS under “System Emergency” at a minimum of every hour until the TEA 3 is terminated. 3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities. 3.4 Re-evaluating and revising SOLs and IROLs. The Reliability Coordinator of the declaring entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Re-evaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the declaring entity who has requested an TEA 3 condition. SOLs and IROLs shall only be revised as long as a TEA 3 condition exists or as allowed by the Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised: 3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection. 3.5 Returning to pre-emergency SOLs and IROLs. Whenever the transmission systems can be returned to their pre-emergency SOLs or IROLs, the declaring Entity shall notify its respective Reliability Coordinator. 3.5.1 Notification of other parties. When an alert has been downgraded, the Reliability Coordinator shall notify via the RCIS the affected Reliability Coordinators, Transmission Operators and Balancing Authorities that their systems can be returned to their normal limits. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 9 of 17 Effective Date: October 1, 2007 4. Transmission Emergency Alert 0 (TEA 0) - Termination. When the declaring Entity is able to respect IROL requirements and is no longer concerned with its ability to respect IROLs, it shall request its Reliability Coordinator to terminate the alert. 4.1. Notification. The Reliability Coordinator shall notify Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Transmission Operators and Balancing Authorities. RCIS Posting Examples Each RCIS posting should be clear and concise. If the actions are being taken as a result of a contingency, the contingency should also be identified as the cause. The following are examples of possible of RCIS postings: TEA 1 (name of RC) is declaring a TEA 1 on the (name of the interface). TEA 2 (name of RC) is declaring a TEA 2 on the (name of the interface). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of (type of load management procedures that have been or expected to be implemented ie voltage reduction, curtailable load reductions) of relief has been (or is expected) to be implemented to respect the limit. These actions are expected to last the next (length of time – hours/days) and should be sufficient to prevent the need for Firm load shedding. TEA 3 (name of RC) is declaring a TEA 3 on the (name of the interface). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of Firm Load curtailments have been (or is expected) implemented to respect the limit. These actions are expected to last the next (length of time –

hours/days). Contingency Example If the TEA is being declared as a result of a contingency the message could be modified simply by adding the contingency description as below: (name of RC) is declaring a TEA 2 on the (name of the interface). This is a result of a contingency on (name of the interface or contingent element). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of (type of load management procedures that have been Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 10 of 17 Effective Date: October 1, 2007 or are expected to be implemented i.e. voltage reduction, curtailable load reductions) to respect the limit. These actions are expected to last the next (length of time – hours/days) and should be sufficient to prevent the need for Firm load shedding. Updates When updating postings only significant changes need be identified. The following is appropriate: (name of RC) remains in a TEA (2 or 3) on the (name of the interface). (amount of MW relief) of (type of load management procedures that have been or are expected to be implemented i.e. voltage reduction, curtailable load reductions, firm load reductions) have been implemented (description of the change i.e. increased/reduce by amount of MW change or identify no change). Standard TOP-004-3 — Transmission Operations Example #1 IROL violation on “X” No Global Adequacy Concerns IROL “X” 500 MW - A to B 300 MW - B to A Intertie Limit Intertie Limit Imp 300 Imp 200 Exp 200 Exp 100 EEA 1 No 2 No 3 No TEA 1 Yes 2 Yes 3 Yes In this example the available generation in A is in excess of its load requirements. The available generation in B is less than its load requirements. Area B will be relying on the full transfer capability of the interface “X” plus an additional import of 100 MW to the maximum limit on the intertie in Area B. With the implementation of the interruptible load and V/R the firm load requirements in B cannot be met without the use of Firm load shedding. • In this scenario an EEA is not required as the BA is able to meet its global BA Total Load 2,500 MW BA Total Gen 2,900 MW BAImpLimit500MW Zone A Zone B Load 1,500 MW Load 1,000 MW Gen available 2,800 MW Gen available 100 MW Imp 0 MW Imp 100 MW Exp 0 MW Exp 0 MW Interruptible 50 MW Load Interruptible 50 MW Load V/R 50 MW V/R 50 MW Balancing Authority “X” Adopted by Board of Trustees: November 1, 2006 Page 11 of 17 Effective Date: October 1, 2007 Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 12 of 17 Effective Date: October 1, 2007 load/generation requirements. • When this situation is forecast a TEA 1 should be issued to indicate the potential concerns with the ability to respect the IROL limit “X” without the use of load management procedures. • When load management procedures are implemented in Real Time to respect the IROL “X”, a TEA 2 should be issued. • When Firm load is curtailed to respect the limit a TEA 3 should be issued. Standard TOP-004-3 — Transmission Operations Example #2 Global Adequacy Deficiency No IROL Violation IROL “X” 500 MW - A to B 300 MW - B to A Intertie Limit Intertie Limit Imp 300 Imp 200 Exp 200 Exp 100 EEA 1 Yes 2 Yes 3 No TEA 1 No 2 No 3 No In this example the available generation in A is less than its load requirements. The available generation in B is less than its load requirements. There is a Global Adequacy deficiency after considering full import capability and utilization of interruptible load and V/R. BA Total Load 2,500 MW BA Total Gen 1,800 MW Zone A Zone B Load 1,500 MW Load 1,000 MW Gen available 900 MW Gen available 900 MW Imp 300 MW Imp 200 MW Exp 0 MW Exp 0 MW Interruptible 100 MW Load Interruptible 50 MW Load V/R 50 MW V/R 50 MW Balancing Authority “X” Adopted by Board of Trustees: November 1, 2006 Page 13 of 17 Effective Date: October 1, 2007 Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 14 of 17 Effective Date: October 1, 2007 • EEA procedures should be followed • There is no need for a TEA to be issued Standard TOP-004-3 — Transmission Operations Example #3 Global Adequacy Deficiency IROL Violation IROL “X” 500 MW - A to B 300 MW - B to A Intertie Limit Intertie Limit Imp 300 Imp 200 Exp 200 Exp 100 EEA 1 Yes 2 Yes 3 No TEA 1 Yes 2 Yes 3 Yes In this example the available generation in A meets its load requirements. The available generation in B is less than its load requirements. There is a Global Adequacy deficiency after considering full import capability. There is also an IROL violation at “X” in the direction of A to B to meet the load requirements in B depending on where load management procedures are implemented. Adopted by Board of Trustees: November 1, 2006 Page 15 of 17 Effective Date: October 1, 2007 • An EEA 1 and a TEA 1 should be issued to identify the potential issues BA Total Load 2,500 MW BA Total Gen 1,700 MW BAImpLimit500MW A B Load 1,500 MW Load 1,000 MW Gen available 1,600 MW Gen available 100 MW Imp 300 MW Imp 200 MW Exp 0 MW Exp 0 MW Interruptible 100 MW Load Interruptible 50 MW Load V/R 50 MW V/R 50 MW Balancing Authority “X” Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 16 of 17 Effective Date: October 1, 2007 • When load management procedures are implemented to manage the transfer from A to B a TEA 2 should be issued (assumes B will be deficient before the global deficiency occurs). • An EEA 2 should be issued when load management procedures are being implemented in A to manage global requirements. • TEA 3 should also be issued when Firm load is shed in B to meet the load requirements in B while respecting the IROL. Standard TOP-004-3 — Transmission Operations Example #4 Transaction Curtailments IROL “X” 500 MW - A to B 300 MW - B to A Intertie Limit Intertie Limit Imp 300 Imp 200 Exp 200 Exp 100 EEA 1 No 2 No 3 No TEA 1 No 2 No 3 No In this example there are no global adequacy concerns. There is an export transaction in B that is causing a limit concern on “X” in the A to B direction. With the available generation in B plus the transfer capability there is no concern for violating the IROL limit. The transaction is creating a situation where it will be required curtailed at some point to prevent the IROL violation. Assuming the TLR procedure would be effective at relieving this constraint regardless of the TLR level (at either the TLR 3 or 5 level) no TEA would be required as there is no concern that the IROL can’t be respected with control actions that don’t involve load management procedures. BA Total Load 2,500 MW BA Total Gen 2,500 MW BAImpLimit500MW A B Load 1,500 MW Load 1,000 MW Gen available 2,000 MW Gen available 500 MW Imp 200 MW Imp 0 MW Exp 0 MW Exp 100 MW Interruptible 100 MW Load Interruptible 50 MW Load V/R 50 MW V/R 50 MW Balancing Authority “X” Adopted by Board of Trustees: November 1, 2006 Page 17 of 17 Effective Date: October 1, 2007
Individual

Chris Scanlon
Exelon
Yes
Yes
Is there a typo in the question? TOP-001 does not have a rev 3. Assuming the intent is to refer to TOP-001-2, R4 we agree.
Yes
Follow existing Guidelines, GADS states “well in advance” as notification for “Planned” outages. This typically means more than 30 days in advance. PJM uses the 30 day definition for “Planned”. Nuclear / INPO uses 28 days (4 weeks) from an INPO definition for “Planned”. 30 days seems to be a reasonable requirement.
No
In general, Exelon supports the revisions and appreciates the work being done by the SDT to consolidate and clarify the requirements. We have some concerns with the langauge in TOP-001-2 R4. "Coordinate" - We believe this needs to be better defined. "Known or expected to have a reliability impact" - Reliability impact needs to be defined better, can measures be identified, such as; cause a system to violate a limit under expected conditions? Consider adding the words “in the judgment of the TOP ” before the word “expected.” Otherwise this may become a point of contenetion and difficulty during an audit. If the GO is not removed (see question 2)the GO is not likely to have the ability to know what reliability impacts its actions might have. "other reliability entities" - needs to be defined. "Unless conditions do not permit such coordination" - if this clause is getting at the issue of time not available, consider “unless based on the reasonable judgment of the TO, considering the facts and circumstances at the time, conditions do not permit such coordination.” We feel the point of the requiremnts should be when a GO/TO knows or reasonably should know that an action will have a substantial adverse reliability impact on another operating entity (define), the GO/TO should inform the other entity and consider that other entity’s input in deciding how to operate, if time permits.
Individual
Michael J. Sonnelitter
NextEra Energy Resources, LLC
Yes
Yes
No comment.
Yes
No comment.
Yes
Individual
Harvie Beavers
Colmac Clarion
Yes
Yes
Particularly since R2 contains no requirement for communications concerning notification of any problems or communication with the GOP. Likely the first time GOP will be aware of condition is at failure of RC/TO efforts to resolve same.
Yes
Assume this is System Operating Limit and Interconnect Reliability Operating Limit (need to cite for first time acronym use as was done with 'BES' in purpose statement). Unsure of exact setpoint of reporting, but would likely be at anytime load approaches or exceeds planned or immediately available generation; perhaps within 2-5% greater then parity.
Yes
Yes
Current policy under some existing contract operators requires initial notification on a rolling 3 year plan and additional

notification to 'dispatcher' at 30 days. Generally, verbal notification is also conducted between generating facilities and Transmission operator on a much shorter and timely basis additionally. Transmission/Distribution company has a similar long range, and short notification cycle.
Yes
During 'blackout' that resulted in this program, GOP's received more intial information on problem and expected recovery from CNN then from 'chain of command'. If response is expected inclusion in information stream must also be included.
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
No
PacifiCorp has no specific subset of SOLs to suggest, however, they must be clear and easily identifiable and measurable. Suggested subsets should be included in the next comment phase for this SAR.
Yes
Yes
The appropriate number of days should be established on a region-wide basis, not a country wide basis. Each region has unique infrastructure that requires specific advance notice.
Yes
Group
Real Time Best Practices Standards Study Group
Frank Koza
No
The Real-time Best Practices Standards Study Group (RTBPSSG) feels that the deletion of TOP-004-2, R4 (Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes) does not provide an adequate level of reliability for the operation of the Bulk Electric System (BES) and the reasoning provided for the removal is flawed. The RTBPSSG believes that this is an important consideration for operations that should not be deleted and that with more deliberations an acceptable measure for such a requirement can be developed. The concept of operating in a known state has long been a fundamental concept of reliable system operations and if this requirement is deleted then there is no requirement to cover this concept. The idea of operating to preclude IROLs or to return to within the limit in Tv does not adequately address this concern.
Group
PJM's NERC and Regional Coordination Department
Patrick Brown
Yes
PJM supports the intent and the concept of comparability as intended by this requirement. However, PJM would note that TOP Emergency Procedures are not identical and are designed around the reliablity needs and capabilities of the individual TOP. When dealing with compliance, the interpretation of what is and what is not comparable could have unintended consequences.
Yes
The data obligations for GOPs to coordinate with its TOPs is covered in TOP-001-2 R1. The operational obligations for GOPs to coordinate with TOPs is covered in IRO-005. IRO-005-3 R1 places a requirement on the RC to have access to operating data (which specifically includes planned generation outages – R 1.9). Thus the RC already has the responsibility to get the data in question. Given that the RC has the authority to request and obtain that data, one could argue that there is no need to also mandate that the GOP coordinate the same data, since that obligation already lies with the RC - see R4).
PJM agrees that reporting should be based upon and restricted to reliability issues. Given the broad scope of the term

SOL as defined in the NERC Glossary, PJM agrees that the requirement should be limited to a subset of the SOLs PJM proposes: 1. The TOP requirement on limit reporting parallel the RC requirement on IROLs 2. The TOP report violations (not exceedences) of any limit predefined by the TOP to be an essential limit (i.e. for a defined local condition that is deemed by the TOP to be of special concern and is not covered by any predefined IROL). This approach provides a TOP the flexibility, when appropriate, to go beyond the definition of BES and to use reliability considerations rather than arbitary formulae to drive its operational reporting.
Yes
PJM agrees that there is no need to include a requirement that focuses on switching procedures.
No
A mandated common time-period would likely conflict with some already FERC-approved procedures. Moreover, a common timing requirement will likely as reduce the benefits and flexibility of some procedures, as it would provide benefits to others.
Yes
Group
Southern Compnay
Hugh Francis
Yes
Yes, the phrase should be reinstated. Also, these actions should be coordinated by the Reliability Coordinator(s). Thus, we believe the verbiage should ultimately be: “provided that the requesting entity has implemented its comparable emergency procedures as coordinated by the Reliability Coordinator(s)”.
No
The GOP needs to communicate problems that could impact normal operation.
The subset will be pre-contingency IROL exceedences, post-contingency IROL exceedences, and real-time facilities experiencing SOL exceedences.
Yes
Redundant requirements in separate standards are both confusing and waste resources.
No
No time limit needs to be established. Entities need to be able to plan short term outages, generation and transmission. The Eastern Interconnection presently has an advanced outage notification through the NERC SDX.
No
TOP-001 R2: The phrase “shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities” could cause compliance issues due to the resulting subjectivity of the identification of other reliability entities. Recommend that it replaced with “shall coordinate its respective operations known or expected to have a reliability impact on adjacent reliability entities”. It should be the responsibility of the adjacent reliability entity to further coordinate, if necessary, other appropriate reliability entities. The Measures and VSLs would need to be modified accordingly. TOP-002 R2 uses the word "plan" as a verb, and then it is referenced in R3 as a noun. This is propagated in the Measures and VSLs. Suggest the following wording change in R2: The Transmission Operator shall have a coordinated plan…… TOP-003 R1.1 - suggest that "Long term" be removed and replaced with "Planned". "Long term" could be interpreted to mean an outage that will not occur for quite some time (long lead time), or an outage that will occur sooner but will last for a long time. All outages should be communicated. R1.2 - Disagree with this requirement. We recommend that it be struck. The TO and the BA must be able to specify formats that can be utilized by their processes to ensure reliability.
Individual
James H. Sorrels, Jr.
American Electric Power
Yes
AEP would suggest that the phrase be reinstated with a change of the word “implemented” to “taken into consideration”. It is important that entities not solely rely on emergency assistance when alternatives may be available. The timing itself may necessitate alternative approaches.
Yes
AEP appreciates the removal of redundant requirements, where possible to do so. We do not see the need for the GOP to be involved.
Yes
While it is expected that the Transmission Operators work in conjunction with the Reliability Coordinators to mitigate most SOL violations, a NERC requirement to report all SOL violations seems impractical. The IROLs provide a clear and logical subset of SOLs that should be reported to the RC.
Yes

Please note the typographical error in question 4. TOP-001-3 in question 4 should read TPO-001-2.
No
The current rules for each region are followed today and coordination is done very well. Seams agreements address the coordination across regions. Therefore, a country-wide period is not necessary from a reliability perspective. If it is otherwise determined to be necessary, AEP believes that it should be done at the IROL level since, by definition, these are the situations with wide area impact.
Yes
Individual
Jianmei Chai
Consumers Energy Company
Yes
An Entity can not be required to take actions for another if the requesting entity has not taken all steps available to them to correct the situation.
No
No
Communication of planned or scheduled outages should take place in the planning phase. Communication should be as early in the phase as possible for all TOs GOs and BAs effected by the outage. To have a nationwide standard is too confining and removes possible flexibility that can come from open communication. TOP-003-0 requires communication of outage information on a daily basis.
No
TOP-003-1 R1.1 needs to be more specific in identifying the 'equipment' to be considered for inclusion.
Individual
Brent Ingebrigtson
E.ON U.S.
Yes
No
The requirement should state that the Generator Operators should be required to "coordinate" with their respective TOP not simply provide data.
No
All SOL exceedances on the BES should be reported to the RC and corrective actions should be coordinated with the RC.
Yes
No
The RCs already have advance notification requirements which TOPs must follow. Most BES facilities have limited impact on neighboring systems. Depending on the level of notification, this could impose an undue burden on Transmisson Operators and field switching personnel in performing needed maintenance. The Regions should identify a subset of facilities (similar to the ECAR Facility Outage Notification Table) subject to advanced notification requirements. Should a country-wide advance notice time period be established it should only apply to 200kV and above.
Yes
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
This phrase should be reinstated.
Yes
GOP should be deleted from this requirement.
Yes
Comments: Report all SOLs that require firm load to be dropped to return transmission elements within limits.

No
Comments (including # of days if appropriate): Oncor Electric Delivery does not believe a country-wide notification period is necessary. As each interconnection has it's unique characteristics, there is no assurance that a common advance notification period would work for all. Additionally, setting a common date within a NERC standard seems inconsistent with the intent of reliability based standards. Advanced notification seems to be more of a market function and is not reliability based.
Group
WECC
Mike Davis
No
Leave phrase deleted and current red line indicates that this is only TO to TO assistance, we believe this is too restrictive and reinstate BA's and GO's.
No
No
All SOL's should be reported to the RC
No
We believe there is a need for clear agreements
Yes
We believe outage notification to the RC for all equipment 100kV and above, and all generator outges of 50MW and above should be a mininum of 96 hours notice in advance.
Yes
Individual
Nied
Con Edison System Ops
Yes
I justify this by saying that this phrase should already included in an operating agreement between the TO's. ...but, having this wording in the standard as well will serve to ensure that TO's have their documents and agreements up to date.
No
The GOP wording should remain.
Let me start out by saying that ConEd reports all SOL's that occur on its system to the NYISO, our RC/BA/TOP. Only those SOL's should be reported to a higher authority (NPCC and above) that result from the TO operating its system in a state which is not allowed. That is, real time SOL's that arise from the TO operating its system on a post-contingency basis due to an exception granted by its RC should not be reported.
Yes
It should be deleted. I see no need for keeping the R2 wording in there. It's confusing and leaves too much up to interpretation. As stated above, the "coordination of operations" wording in R4 would suffice.
Unless the piece of equipment is in a direct neighboring system, what utility would this offer to a TO? "Operations are already coordinated" amongst neighboring TO's with regard to tie-lines. It would not offer much in the way of information on how we operate our system. However, ConEd already sends notification of all of its approved outages on the Bulk Electric System to the NYISO via email automatically. So, I dont think it would be difficult to do if someone decides that they want 7 or 10 day notifiation on something. If this requirement came into being, the NYISO could then disburse COnEd's outage info to NPCC and rest of the East. A hard-line 7 or 10 day rule will be tough to enforce though. Many outages get approved much closer to the actual date...many within 2 days of the start.
No single concern. Each revision should be analyzed on its own merits.
Individual
Kasia Mihalchulk
Manitoba Hydro
Yes
Yes

No
IROL's only
Yes
No
We do not believe there is a reliability need to establish an industry wide advance notification procedure for transmission outages. We believe that the need for advance notification of transmission outages should be identified completely between the TOP and RC in their outage coordination procedures.
Yes
Individual
Ed Davis
Entergy Services
No
There could be situations in which the TOP requesting support cannot implement comparable procedures. For instance, if reconfiguration from a neighboring system would resolve the situation, but reconfiguration on the requestor’s system would not.
No
The status of large generators can have a reliability impact on other reliability entities, and they should be included in this standard.
Instances where an IROL is exceeded should be required to be reported to the RC. It should be left to the RC and TOP to agree to other SOLs that are important enough to be required to be reported to the RC.
Yes
No
There are processes already in place to ensure that outages are coordinated between affected systems. Creating a nation-wide requirement to set an advance notice time is not in the best interests of reliability. Rather flexibility should be allowed to coordinate and agree upon required maintenance activities that are necessary to ensure continued reliability.
Yes
Individual
Greg Rowland
Duke Energy
Yes
No
We believe it’s critical for the GOP to coordinate operations with the TOP.
Yes
Given that geography varies, system interdependencies and ratings philosophy, TOP/RC should agree on what to report.
Yes
No
This comment form is not the right place to address this issue. We would have significant concerns with the idea – too much to support a requirement that hasn’t been drafted yet. Existing processes are in place between neighboring entities to exchange this type of information.
No
- TOP-001 R2 Need to change “affected” to “adjacent”, and in the VSLs. - TOP-001 R4 Change “other” to “adjacent”, and in the VSLs. - TOP-001 R4 If coordinating means that we’re posting the information on SDX, then we are in agreement. - TOP-001 R6 Need clarification on what Tv means. Will we be able to establish variable Tvs based upon the specific IROLs? - TOP-001 R7 Where has this requirement been moved to, or has it been deleted? If it has been deleted, why? - TOP-002 R1 Need to add (N-1) after Contingency, and in the VSL. - TOP-002 R2 does not require a written plan but R3 requires notification of entities in the plan. - TOP-002 R3 VSLs should be changed back to what they were before this revision. - TOP-003-1 R1 The term “NERC Functional Model” should not be used in a requirement because it reduces clarity, due to fact that the NERC Functional Model is evolving over time.

Individual
Kirit Shah
Ameren
Yes
No
GOPs need to coordinate their activities. For instance, a small tube leak might not mandate an immediate outage for a plant electrically near a known SOL/IROL area. To the extent the GOP and TOP coordinate when the outage to repair this condition will occur, BES reliability benefits.
Yes
No
Agreements (formal or informal) are necessary to describe the conditions under which the coordinated switching in TOP-001 takes place. It will be impossible for Transmission Planners to properly analyze the conditions that can be expected if there are no “rules” for operation.
No
First, the definition of planned outage is anything but an industry standard. So the rules around timing are putting the cart before the horse, And, anything in “days” is not practical given the need to get to short-term planned maintenance and the impacts of weather and forced outages on these planned outages. If a notification time is absolutely deemed necessary, 30 minutes to 1 hour would be workable under a mandatory, enforceable NERC standard framework.
Yes
The team has done a significant amount of work in getting these standards cleaned up. There was too much duplication and uncertainty.
Group
SERC OC Standards Review Group
Jim Griffith
Yes
Also, it is not clear in the context of TOP-001 what kinds of assistance an operator of transmission should give to another Transmission Operator (for example, refer to EOP-001, R1 for clarification)
No
Yes
The subset of SOLs, other than IROLs (which must be reported), should be agreed upon between each Reliability Coordinator and the TOPs within the RC’s reliability area.
Yes
If the SDT agrees with deleting R2, we suggest that R1 should be included in TOP-002 and TOP-004-3 retired.
No
A time limit does not need to be established. Entities need to be able to plan short term outages, both transmission and generation when conditions permit in order to minimize impacts to the reliability of the system. For example, a transmission line in need of maintenance might only be available upon the outage (forced or planned) on a particular generator. With a standard in place, this opportunity would be missed. Delaying maintenance on a transmission line puts it at a greater risk of a forced outage.
Yes
TOP-001 R2 - The phrase "shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities" could cause compliance issues due to the resulting subjectivity of the identification of other reliability entities. We recommend that it replaced with "shall coordinate its respective operations known or expected to have a reliability impact on adjacent reliability entities". It should be the responsibility of the adjacent reliability entity to further coordinate, if necessary, other appropriate reliability entities. The Measures and VSLs would need to be modified accordingly. Top-001, Requirement 4 - we suggest changing “other reliability entities” to “adjacent reliability entities”. TOP-002 R2 uses the word "plan" as a verb, and then it is referenced in R3 as a noun. This is propagated in the Measures and VSLs. We suggest the following wording change in R2: “The Transmission Operator shall have a coordinated plan...... “ TOP-003 R1.2 – We disagree with this requirement and we recommend that it be struck. The TOP and the BA must be able to specify formats that can be utilized by their processes to ensure reliability.
Group
FirstEnergy Corp
Doug Hohlbaugh
Yes

We support reinstating the proposed text and it should be clarified, provided that it can be shown that the action requested to assist the other party will mitigate an adverse reliability problem. FE suggests that the text should indicate "provided that the requesting entity has implemented its comparable emergency procedures capable of lessening or mitigating the impact of the emergency and that the assistance requested will help to alleviate an adverse reliability problem."
No
TOP-001-2 R4 requires the actions of the GOP be coordinated with impacted entities while TOP-003-1 R4 requires the GOP to provide data to the TOP and BAs. These are two completely different aspects of the BES operation and both need to be addressed by a standard.
Yes
The question as written does not lend itself to a yes/no answer, the selection of yes was made to indicate that we agree some subset of SOL, when exceeded, warrants the a TOP notification to the RC. FE believes that the appropriate subset are those SOLs that are associated with a previously defined Interconnection Reliability Operating Limit (IROL) as determined via the FAC-014 reliability standard.
Yes
Yes, we agree with the recommendation to delete TOP-004-4 R2. Since this change would leave only one requirement within the TOP-004-4 standard, we urge the team to consider incorporating the requirement into another standard. One suggestion is consider adding the requirement to standard IRO-005-3 titled "Reliability Coordination — Current Day Operations". This could be added as a new requirement of IRO-005-3 or possibly a sub-requirement of requirement R11 of the IRO-005-3 standard. Alternatively, the requirement could be placed into the TOP-001 standard.
No
We do not believe there is a reliability need to establish a common industry wide lead-time for planned BES facility outages. It should be left to the RC and the applicable entities that it monitors (TOPs, GOPs) to establish agreed upon outage coordination procedures. In fact, it should not be expected that a minimum lead-time must always be rigidly adhered to. Consider that many transmission lines can only be taken out of service during a generator outage. If generator unit experienced a forced outage that would permit certain transmission lines to be maintained, such maintenance should not be delayed to simply adhere to a specific lead-time requirement. The RC's and their monitored entities should be given the flexibility to develop a process that is suitable to meet their needs.
No
The drafting team's response to FE's fifth comment in the Draft 1 Question 12 is not sufficient for us to understand their thought process on the matter. Our prior comment raised a concern with the removal of TOP-007-0 R3 that states, "A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load …" The SDT responded that this matter is covered in EOP-001-0, Requirement R3.3 that states, "R3. 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: … R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities." The SDT is proposing to retire PER-001 and FE believes the PER-001 requirement R1 and its associated measure M1.4 should be re-enforced within the TOP standards. This operator authority was a focal point of recent readiness evaluations within the industry and should be explicit within a TOP requirement. We would appreciate further explanation from the SDT if they feel the change is still not required. FE disagrees with the SDT's response to our comment on Draft 1 Q4 which questioned which contingencies are required to be evaluated within the operating horizon. The prior TOP-002-2 requirement R6 stated "R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements." This concept is lost in the newly proposed TOP standards. In responding the SDT stated that "the Transmission Operator is not limited to single Contingencies or bus faults but must study any and all conditions that may result in exceeding any of its System Operating Limits during anticipated normal conditions as stated in the Requirement. The potential Contingencies to be studied are limited to those spelled out in the TPL standard." FirstEnergy does not agree that there is an expectation to cover all TPL contingencies within the operating horizon. As vetted by industry in the recent proposed and subsequently withdrawn SAR that proposed to evaluate "credible multiple contingencies" it is clear that studies within the planning and operations horizon are distinctly different and that there is no expectation to cover events in real-time or within the operating horizon (next day, next month, through one year out) beyond single contingency. We ask the SDT to clarify their comment in this regard. We would like the SDT to explain why it found the need to introduce the term "each" in requirement R1 of TOP-002-1. As re-worded, the focus of the compliance audit may become too structured on strict adherence to each directive rather than the TOP meeting the intent of the RC's directives. If the wording remains, we believe the VSLs can be better graded and that missing a single directive should not warrant a severe VSL. Many of the proposed VSLs use a quartile approach (0-25%, 25-50%,50%-75% and >75%) of gauging if some reliability action was missed. FERC in its VSL Order dated June 19, 2008 took exception to the quartile approach and felt it violates its Guideline 1 "Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance" see paragraphs 19 through 21. The VSL DT revised the VLS that previously used a quartile score to reflect a 0-5%, 5%-10%, 10-15% and >15% graded VSL approach. Its suggested that the SDT reconsider its use of quartile VSLs. We believe the VSLs for TOP-001-2 R6 violates the Commission's Guideline 4 established in their VSL order. The VSLs are based on the number times the

TOP did not act to mitigate the magnitude and duration of an IROL exceedance within its Tv. However, the associated requirement states “The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL’s Tv.” Note that the requirement talks about “an IROL” in the singular. Thus, failure to act on one occasion is a single violation. Failure to act on two occasions is two separate violations not a higher VSL. We suggest that a binary Severe VSL be selected or that you modify the requirement to consider IROLs in the plural. In TOP-003-1 R1.1 second bullet the SDT introduced a new requirement that for data exchange related to equipment at voltage levels below the BES and left the need for this data at the discretion of the TOP or BA. FirstEnergy believes the inclusion of equipment lower than normal BES levels should not be introduced on an ad-hoc standard by standard basis. Rather, if such equipment is deemed necessary for the reliability of the BES then the Facilities may need to be subject to other reliability standards such as vegetation management, preventative maintenance, etc. Inclusion of such equipment should be a registration issue handled through the Regional Entity and not within individual standard requirements. However, providing such data could be requested and provided on a voluntary basis, but if the equipment is deemed essential for BES reliability other standards likely apply.
Group
Dominion Resources Inc.
Jalal Babik
Yes
As currently written an entity could be found non-compliant for not providing emergency assistance to a requesting entity that is not willing to help itself. That punishes the wrong party.
Yes
We support the change. FERC Codes/Standards of Conduct prohibit transfer of non-public transmission information to ‘marketing entities’. Most staffs on the ‘transmission side’ of the industry (TO, TOP, TP, RC) are reluctant to share any non-public information with those on the ‘generation side’ (GO, GOP) because they are unsure whether or not those staffs are deemed ‘marketing entities’.
Yes
In addition to IROLs, the subset of SOLs that need to be reported should include any other SOL exceedances that the RC requests notification of and, in the Eastern Interconnection, any other SOL exceedances associated with permanent, reliability flowgates as defined in the NERC Book of Flowgates.
Yes
It is not clear what an agreement between TOPs to “specify switching” of tie lines is supposed to be. If it is supposed to be an interconnection agreement, those are usually between Transmission Owners. Requirement R2 can be deleted.
No
(including # of days if appropriate): We don’t recommend a country-wide advance notice. However, we agree that it is within the purview of the Reliability Coordinators to reach agreement with the applicable entity and set outage reporting requirements to meet their reliability assessment needs without the development of a new NERC reliability standard.
Yes
TOP-001 uses the term ‘reliability entities’ in the purpose statement while TOP-003 uses the term ‘functional responsibilities’. The Functional Model uses the term ‘Responsible Entities”. We suggest that NERC and the SDT make every effort to use consistent terms. We continue to have concerns with the current standards review/approval process. Having to make comments on new draft standards that are predicted upon other draft standards that have not been approved is a non-productive process. As stated in the implementation plan “Changes made in this project to TOP-005-1, R1; TOP-007-0, R4 are dependent on corresponding changes being approved in Project 2006-06 Reliability Coordination: • COM-001-1: Telecommunications • COM-002-2: Communications and Coordination • IRO-001-1: Reliability Coordination – Responsibilities and Authorities • IRO-002-1: Reliability Coordination – Facilities • IRO-014-1: Procedures to Support Coordination between Reliability Coordinators • IRO-015-1: Notifications and Information Exchange between Reliability Coordinators • IRO-016-1: Coordination of Real-Time Activities between Reliability Coordinators • PER-004-1: Reliability Coordination – Staffing • PRC-001-1: System Protection Coordination”
Group
Northeast Power Coordinating Council
Guy Zito
Yes
It is expected that further details of emergency assistance to be provided would be covered in Operating Agreements.
No
We believe there are occasions when a GOP may need to take actions that would require coordination with or notification of the RC/TOP/BA or others who could be impacted. At this time it is not clear what other standards could obligate the GOP to do so if the GOP were removed from this requirement.
No
System Operating Limits are meant to “ensure operation within acceptable reliability criteria”. Understanding that there is a subset of more critical SOL’s defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the

actions being taken to address the exceedances which can be accomplished via SCADA or other means of action and communication when necessary.
No
Operating Agreements cover activities other than switching. We believe the requirement should be retained but any duplication eliminated.
No
While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region. Such notification requirements should be established within each region based on the needs of the RC.
No
We disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time." SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? TOP-002-3 M1--Power flow study results will not be available for those days where studies are not required. Those days may be considered pre-studied or a normal “studied” state. How is this to be measured? TOP-002-3 R2, R3 – A plan should be required when the review warrants it and should include both IROL and SOL. In a normal state there may already be existing coordination between reliability entities with no need to re-communicate. TOP-003-1 R1: Reference to the Functional Model in the requirement may not be appropriate. This requirement may be clearer if the specific responsibilities are included. R1.1 “Long Term Outages” should be defined or clarified. What about other outages that are potentially impactive? In general, it is not clear that the data specification includes real time communications or operational planning requirements. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some voice recorders are designed to retain data for 90 days. Have data recordings stored longer than 90 days only if requested by the RC or TOP.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Yes
No
If a GOP is to comply with directives from a TOP in R1, then a requirement "to coordinate operations" is needed in R4.
Yes
The IROL subset needs to be reported.
No
Either leave TOP-004-3, R2 as is or move a requirement for an Agreement into TOP-001-3, R4.
No
At this time I see no reliability benefit for this requirement.
No
See responses to previous questions.
Group
Midwest ISO Stakeholders Standards Collaborators
Jason L. Marshall
No
When a compliance audit is conducted, the compliance auditor will not be evaluating a third party TOP to determine if they implemented all of their comparable procedures prior to requesting emergency assistance. They will simply review if the TOP being audited responded to the request for emergency assistance. If they did not, they are not necessarily in violation of the requirement because the requirement does recognize legal restrictions for not responding. Thus, if a third party TOP requested the audited TOP to shed load but had not done so themselves, the audited TOP may have appropriately and compliantly refused because their state laws and regulations prevent them from shedding load for neighbors unless they are doing the same.
No
What if the unit is a reliability must run unit? With this requirement in place, the GOP may be more proactive in keeping the unit running (i.e. willing to take a greater risk damaging the unit if there is already a problem with the unit). Without

the requirement, the GOP may shut the unit down at the first sign of any problem.
All SOL exceedances should be reported to the Reliability Coordinator. The Reliability Coordinator has the ultimate reliability authority. If the RC is not made aware of an SOL exceedance, how can the RC evaluate if the exceedance is actually approaching an IROL? Further, multiple SOL exceedances can be a sign of a greater reliability problem that the RC needs to rectify.
Yes
No
We do not believe there is a reliability need to establish an industry wide advance notification procedure for transmission outages. We believe that the need for advance notification of transmission outages should be identified completely between the TOP and RC in their outage coordination procedures. In fact, we believe such a requirement could actually be a detriment to reliability. Consider that many transmission lines can only be taken out of service during a generator outage. If the generator were to trip, the transmission line could not be taken out of service for lack of sufficient advance notice delaying the maintenance of the line and, thus, increasing the potential for the line to be forced out. It is not clear what reliability benefit could even be achieved by having an industry wide advance notification requirement. We believe that should such a requirement become a reality, there will be further reliability detriment as TO/TOPs delay maintenance in a struggle to transition to comply with such a requirement.
No
We believe removing the requirements for SOLs in this standard will make it unacceptable to FERC. Thus, the drafting team will have to start over when FERC remands the standard. The VSLs for TOP-001-2 R2 are based on the number of times the TOP did not inform the RC of Emergency conditions. Over what time period does this apply? In perpetuity? From last compliance audit? We believe the VSLs for TOP-001-2 R6 violates the Commission's guideline 4 established in their VSL order. The VSLs are based on the number times the TOP did not act to mitigate the magnitude and duration of an IROL exceedance within its Tv. However, the associated requirement states "The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv." Note that the requirement talks about "an IROL" in the singular. Thus, failure to act on one occasion is a single violation. Failure to act on two occasions is two separate violations not a higher VSL. We suggest that a binary Severe VSL be selected or that you modify the requirement to consider IROLs in the plural. In TOP-002-3, the drafting team should consider making R2 a sub-requirement of R1. Isn't it a sub-component of the assessment the TOP must have in R1? R3 should be made sub-requirement of R2. M1 deviates from R1 in that M1 says that the TOP shall have evidence that it performed an assessment while R1 says it shall have an assessment. Likewise, the VSL differs from the requirement in the same way and should be made to match the requirement. In TOP-003-1, we note that R3 requires the BA to distribute its data specification but there is not a similar requirement to have a data specification like R1 for the TOP. We believe R3 belongs in the BAL standards. We also suggest that the VSLs for R4 and R5 could be graded to include multiple levels. In R4, we believe the additional VSLs could be defined based on the percentage of data that is not supplied. The VSLs for R5 could be graded based on the number TOPs and BAs that the TOP did not supply data and information to. We further believe that the portion of the requirement in R5 that applies to the BA should be moved to the BAL standards. In TOP-004-3, M1 appears to be a measure of non-compliance with R1. Aren't measures supposed to identify how compliance is measured not non-compliance? The VSLs measure non-compliance.
Group
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool
Frank Gaffney, Regulatory Compliance Officer
Yes
This is a tough one to answer, there are conceivably two types of timelines for emergencies, e.g., an emergency where response is required within minutes vs. response during a longer period of time. If a response is needed in minutes, such as post-contingency with a facility within a 10 minute emergency rating, there may be no time for a sequential step-by-step process where deleting the phrase is appropriate and entities will need to trust that the TOP is making the correct decisions. If there is time, such as a pre-contingency forecast that an element may exceed a rating, but the contingency has not occurred, then a step-by-step sequential process where the TOP in an emergency state takes action first is more appropriate. How about something like: "provided that, time permitting, the requesting entity has implemented its comparable emergency procedures". Of course this introduces the difficult to measure "time permitting", but maybe this could be clarified as pre-contingency vs. post-contingency
Yes
Yes, it is appropriate to delete GOP from this requirement. However, consider adding a bullet under TOP-003-1 R1.1 that includes planned and unplanned generator capacity changes (which is then referred to in R4), similar to the current TOP-002-2, R14.1.
Yes
We assume "Yes" means we agree that a subset of SOLs should be reported. First, any voltage stability and transient stability limited SOLs should be reported. Second, for thermally limited SOLs, an equipment voltage class threshold for the facility with the thermal limit is probably the easiest to implement, e.g., > 200 kV, and seems consistent with other

standards with this threshold (e.g., PRC 023, FAC-003). We are a bit confused with handling of IROLs, IRO-009-1 seems to make the RC responsible for managing IROLs, and therefore, no reporting of IROLs seems to be needed in TOP-001-2; hence, should SOLs that are IROLs be reported? Note that there seems to be a conflict between this requirement and the requirements of IRO-009-1, e.g., both the TOP and the RC are being held accountable to managing IROLs. This arrangement seems fraught with potential for confusion. We believe only one entity ought to be responsible for managing IROLs, and that entity should probably be the RC. This comment applies to R6 of TOP 001 2, and this comment also applies to the conflict between TOP-004-3 R1 and IRO 009-1 R4, which assign the responsibility of operating within IROL limits to both the RC and TOP. Who has primary responsibility? Who takes leadership in a situation? Is RC primary with TOP back-up?
Yes
If the requirement is deleted, you might want to consider changing the time frame to include the Planning Horizon to clarify that operating procedures / agreements between utilities are required in the long term (e.g., interconnection agreements, etc.), as well as to align with FAC-002 and the TPL standards
Yes
We believe that such a provision is necessary to enable coordination of major maintenance outages to ensure resource adequacy for the region for generation related outages, and to ensure coordination of scheduled transmission outages in a localized area, for seasonal assessment purposes. There are probably two types of maintenance to be addressed, major maintenance schedules, and more minor maintenance due to equipment failure that does not cause an unscheduled outage. First, each region does seasonal assessments, it may be a good idea to tie major maintenance schedules as input into the region’s seasonal assessments, but allow flexibility in the actual schedules of these major maintenance schedules, with a reasonable input time frame to provide that input, e.g., two months before the start of the season. Second, there will always be unexpected maintenance schedules of shorter duration due to equipment failure that does not cause the facility to have an unscheduled outage, but, needs to be corrected. These are much more difficult to coordinate and schedule and may not allow a multi-day advance notice, so, maybe we could make the requirement only apply to major maintenance schedules.
Yes
We generally support the revised standards, but did have a few additional comments: • The data retention is significantly longer than earlier standards, e.g., three years rather than 3 months, and the data retention is not consistent between standards, e.g., TOP-001-2 is one year, TOP-002-3 is six months, TOP-003-1 and TOP-004-3. What is your reasoning behind these changes and the inconsistencies between them? Also, saving daily operating data for three years seems a long time. • TOP-002-3 R1 probably ought to refer to TOP-003-1 as one of the sources of data for the assessments. • Do the standards require current day plans? TOP-002-3 and IRO-004-1 only covers next day. Are we making current day equivalent to real-time, and therefore not requiring a plan for the current day? • TOP-002-3 R1 assigns the same task to the TOP that the RC has in IRO 004 1 R1, although not as confusing as real-time operations with two entities responsible for the same thing, as discussed above in the comments to TOP-001-2, this also has potential for confusion of roles, responsibilities and actions. Should only one entity be responsible for next day plans, e.g., the RC? Or is the distinction that RCs study interfaces, whereas the TOPs assess its entire system? If so, should such a distinction exist?
Individual
Gregory Campoli
New York Independent System Operator
Yes
No
We believe there are occasions when a GOP may need to take actions that would require coordination with or notification of the RC/TOP/BA or others who could be impacted. At this time it is not clear what other standards could obligate the GOP to do so if the GOP were removed from this requirement.
No
System Operating Limits are meant to “ensure operation within acceptable reliability criteria”. Understanding that there is a subset of more critical SOL’s defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances.
No
: No, this requirement should not be deleted. Agreements among TOPs are needed to ensure proper coordination of operational plans and actions. However, we do not agree that “switching of synchronous tie lines” should be specified in the requirement, nor should it be the only action specified in a TOP agreement as there are other items such as coordinating reactive power and voltage support, planned and forced outages, emergency operation, restoration, re-synchronization, etc. that need to be included in the agreement. We suggest this requirement be revised to: “Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specifies operation coordination among them.”
No
This should be handled on a local or regional basis. There is a wide diversity of systems in place with reporting

requirements defined, in some cases based in market requirements. It may not be reasonable to place the least common requirement on all entities in NERC.
No
We generally support the direction the SDT is moving but would require consideration of the comments provided in this transmittal. What is replacing TOP-001 R7? The requirement was previously TOP-008-R2, got moved to TOP-001 R7, but now both TOP-001 R7 is deleted and TOP-008 is deleted. Is there still going to be a requirement to use the most restrictive limit when multiple entities have different limits? TOP-003-1 makes reference to functional responsibilities and responsibilities per the NERC Functional Model. We do not agree with these references since it is unclear the status of the NERC Functional Model and how it relates to the NERC Standards. It has been noted that the NERC Functional Model is only for guidance and is not a standard. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some are designed to retain data for 90 days. The SDT should take into consideration the storage media. In some cases equipment is changed and the data may not be obtainable, or cost prohibited.
Individual
Alice Murdock
Xcel Energy
No
Yes
Yes
We agree R2 is not necessary and should be deleted. Additionally, the use of the term "Agreements" is concerning, especially when the additional language requires one to "specify switching".
Yes
Yes
In general, we appreciate the drafting team's work and feel the drafted standards are a positive move towards more simplified requirements. However, we do have some concerns, detailed below. TOP-001 >We feel the new R3 should also be applicable to BAs & GOs. >R4 - The phrase “reliability entities” needs definition. It is not clear who is being referenced. >R6 – consider adding language to include SOLs. TOP-002 >R1- We assume that the use of the defined term “Contingency” implies N-1 contingency planning. Yet, it is not clearly stated as such and therefore open to some interpretation. We recommend adding language to clarify, similar to the current version. >R2 – What is the intent here? Please clarify if planning is intended to entirely prevent the exceedence of an IROL, or to not exceed an IROL Tv. >R3 - The phrase “reliability entities” needs definition. It is not clear who is being referenced. >Deletion of the current R3 raises a concern as to what now requires LSEs and GOPs to coordinate their planning. This can present problems with TOPs and BAs attempting to collect needed data. >Deletion of current R8 – where is this covered elsewhere? TOP-003 >R1.1 “long term” needs more definition; we recommend changing to operating horizon >R1.1 We do not believe it was the drafting team’s intent to require outage reports of all BES components (breakers, etc), nor do we feel that is reasonable. We recommend the addition of a clarifying statement such as: “BES components specified by the Transmission Operator and Balancing Authority.” >R5 uses the phrase “immediate responsibility” – suggest changing this to “responsible for real time operations.” >It is not yet clear where the current R2 and R3 are being moved to. The previous draft indicated they would be moved to IRO standards. Please provide the link to those drafts or the project they are being worked under.
Individual
Kathleen Goodman
ISO New England Inc.
Yes
Yes
We believe this is covered by various other requirements in various other standards and need not be maintained here.
No
System Operating Limits are meant to “ensure operation within acceptable reliability criteria”. Understanding that there is a subset of more critical SOL’s defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances, either through SCADA or other means. This should ensure keeping an eye on SOLs so that cascading into an IROL will not occur.
Yes
We beleive this is sufficiently covered by the Standards in their totality.
No

While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region and, as such, notification requirements should be established within each region based on the needs of the RC. These may be dictated by an entities market structure, which should not be influenced by NERC Standards.
No
We disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time." SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? TOP-002-3 M1--Power flow study results will not be available for those days where studies are not required. Those days may be considered pre-studied or a normal “studied” state. How is this to be measured? TOP-002-3 R2, R3 – A plan should be required when the review warrants it and should include both IROL and SOL. In a normal state there may already be existing coordination between reliability entities with no need to re-communicate. TOP-003-1 R1: Reference to the Functional Model in the requirement may not be appropriate. This requirement may be clearer if the specific responsibilities are included. R1.1 “Long Term Outages” should be defined or clarified. What about other outages that are potentially impactive? In general, it is not clear that the data specification includes real time communications or operational planning requirements. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some voice recorders are designed to retain data for 90 days. Have data recordings stored longer than 90 days only if requested by the RC or TOP.
Individual
Armin Klusman
CenterPoint Energy
No
CenterPoint Energy does not see a reliability-related need to establish a continent-wide requirement that specifies the time frames for advance notification of planned outages. Such an approach does not appear practical considering the varying types of outages (circuit breakers, transformers, buses, and lines) and differing long-range and short-range scheduling time frames. As regional practices are already in place, CenterPoint Energy recommends outage scheduling time frames continue to be determined on a regional basis.
No
CenterPoint Energy believes reliability requirements should not include vague and unmeasurable, fill-in-the-blank provisions, like those shown in TOP-003 Requirement 1. R1 states “Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model.” In addition, CenterPoint Energy disagrees with the accompaning TOP-003 Requirement 4 that requires numerous entities to comply with fill-in-the-blank provisions developed through R1. As written, R1 leaves it open to the whim of a Transmission Operator or Balancing Authority to conjure a list of required data, without any process for impacted entities to argue the reasonabless of the data. In R1.1, the SDT has added two examples of required data by stating “Long term outages of Bulk Electric System equipment when they are known” and “Equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority”. These vague examples leave it to the total discretion of a Transmission Operator or Balancing Authority. CenterPoint Energy recommends rewording Requirement 1 and deleting TOP-003 Requirement 4.
Group
MRO NERC Standards Review Subcommittee
Michael Brytowski
Yes
Yes
No
IROLs are a sufficient subset to report.
Yes

No
After the review of the paragraph 1612 of the FERC final order 693, the MRO NSRS would like them to be more specific about the type of outages and consistent with the Reliability Coordinator's requirement; the Reliability Coordinator has a wide-area view. How would this country-wide advance notice improve reliability for two independent systems not physically interconnected?
Yes
See response to question number 5 which is "After the review of the paragraph 1612 of the FERC final order 693, the MRO NSRS would like them to be more specific about the type of outages and consistent with the Reliability Coordinator's requirement; the Reliability Coordinator has a wide-area view. How would this country-wide advance notice improve reliability for two independent systems not physically interconnected?" In TOP-001-1 R1, what is a reliability directive? Should this be defined? The NERC standard COM-002-2 talks about the RC issuing a reliability directive, what is a directive? Not every communication is a directive; please clarify what is a reliability directive. Should each directive start off by stating that it's a directive and that 3 way communication should be used? (In the MISO Business Practice RTO-OP-002 R7, Telephone Communications Protocol, section 3.2.1, when issuing a Reliability Directive the following must be stated: "This is a Reliability Directive and I will need you to repeat it back.") Other MISO Business Practices which discuss reliability directives are RTO-BPM-006-R2 and RTO-EOP-003-R8. The current standard TOP-002-2a includes an interpretation of R11 stating among other things that a "unique" study is not needed for each operating day. The MRO NSRS recommends revising the TOP-002-3 R1 to include this interpretation. For the TOP-003-1 R1, "Each Transmission Operator and Balancing Authority shall have a documented specification for data to support its Real-time monitoring and reliability assessments required to fulfill their respective responsibilities per the NERC Functional Model.", the MRO NSRS believes that this phrase "NERC Functional Model" should be removed since it is unclear as it reads now and it should be replaced with "R1.1, R1.2, and R1.3".
Group
IRC Standards Review Committee
Ben Li
Yes
No
We believe there are occasions when a GOP may need to take actions that would require notification to the RC/TOP/BA or others who could be impacted. This is not following directives; it is for the GOP to make known to others of actions it will take that can have a reliability impact or affect others. If a predetermined list of actions to be communicated is established, then this requirement is not needed. At this time it is not clear what other standards provide this list which collectively obligates the GOP to notify parties that would be impacted. If the requirements for a GOP to communicate and coordinating actions such as removing AVR from service, derating real and reactive capabilities, removing units, protective relays, stabilizers, exciters, etc. out of service, are covered by other standards, then we do not disagree with the proposed deletion.
No
(Please note that CAISO abstained from the following comments) System Operating Limits are meant to ensure operation within acceptable reliability criteria. We understand that IROL is one subset of the SOL's but there is another subset of SOLs that either have special relevance to the TOP, or though not determined to be IROLs at the onset, would have an adverse impact on interconnected system reliability if their exceedances are not mitigated or are simply ignored. We believe the TOPs are in the best position to determine this subset, subject to the concurrence of its Reliability Coordinators.
No
(Note that CAISO abstained from the following comments) No, this requirement should not be deleted. Agreements among TOPs are needed to ensure proper coordination of operational plans and actions. However, we do not agree that "switching of synchronous tie lines" should be specified in the requirement, nor should it be the only action specified in a TOP agreement as there are other items such as coordinating reactive power and voltage support, planned and forced outages, emergency operation, restoration, re-synchronization, etc. that need to be included in the agreement. We suggest this requirement be revised to: "Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specifies operation coordination among them."
No
This should be handled on a local or regional basis. There is a wide diversity of systems in place with reporting requirements defined, in some cases based in market requirements. It may not be reasonable to place the least common requirement on all entities in NERC.
No
(1) We believe there is a fundamental principle that TOPs need to operate their systems within SOLs. We propose the SDT re-instate the deleted words from TOP-004 R1 that address SOLs. Recognizing that not all SOLs have an impact on interconnected system reliability if their exceedances are not mitigated within some target time period, we propose the SDT consider qualifying the SOLs which the TOP must operate within along the same line as we propose in our

comments under Q2, namely, the set to be identified by the TOP subject to its RC's concurrence. (Please note that ERCOT abstained from these comments) To more fully address the issue with some SOLs that do not have any reliability impacts, we propose the SDT consider revising the definition of SOL. This will eliminate the need for each TOP to identify this subset and obtain the RC's concurrence. (2) We generally support the direction the SDT is moving but would require consideration of the comments provided in this transmittal. What is replacing TOP-001 R7? The requirement was previously TOP-008-R2, got moved to TOP-001 R7, but now both TOP-001 R7 is deleted and TOP-008 is deleted. Is there still going to be a requirement to use the most restrictive limit when multiple entities have different limits? TOP-003-1 makes reference to functional responsibilities and responsibilities per the NERC Functional Model. We do not agree with these references since it is unclear the status of the NERC Functional Model and how it relates to the NERC Standards. It has been noted that the NERC Functional Model is only for guidance and is not a standard.
Individual
Catherine Koch
Puget Sound Energy
Yes
Yes
Yes
Interconnections or major paths as specified by the region only
Yes
Yes
Individual
Dan Rochester
Independent Electricity System Operator
Yes
This phrase pre-supposes that the assisting TOP will need to implement emergency procedures in order to assist the requesting TOP. This may not always be the case if the assisting TOP is willing and able to provide assistance without any detrimental impact to its own system. If such an arrangement were to be permitted, the details would be covered in Operating Agreements between the two entities. The SDT may therefore wish to consider catering for this and other possibilities by appending the clause "…subject to the provisions of operating agreements where established…"
No
TOP-001-2 R4, as written, stipulates the need for coordination of operations, i.e., coordination with or notification of the RCs/TOPs/BAs or others who could be impacted by the GOPs actions and operational plans. This is more than merely providing data, which is covered by TOP-003-1 R4. On the latter requirement (TOP-003-1, R4), we are unable to find an explanation for the addition of "….including, but not limited to:" and the bulleted items that follow. It suggests that only the listed information needs to be provided. Requirement R1.1 would serve the intended purpose by simply saying: "A list of required data to be exchanged." We suggest deleting the added wording and bullets.
No
System Operating Limits are meant to "ensure operation within acceptable reliability criteria". Understanding that there is a subset of more critical SOL's defined as IROLs, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances. Further, this question runs counter with the SDT's proposal/decision to remove the requirement for the TOP to operate within SOLs from TOP-004-2, R1, to which we expressed a strong disagreement when commenting on the last posting. If there is no requirement for the TOP to operate within SOLs, then what purpose would it serve for the TOP to report exceeding SOLs? Similarly, what purpose would TOP-002, R1 serve? We suggest the SDT to first establish a principle regarding the need to operate within SOLs, then consider the implication of removing such a requirement from TOP-004-2, R1, when assessing other related requirements such as reporting exceedance (TOP-001, R5), performing day ahead assessment (TOP-002, R1), and developing methodology to calculate SOLs (FAC-014), etc. Finally, if the industry wishes to reduce the potential number of reports, such as those instances in which the SOLs are temporarily exceeded (popping in and out), a time and/or a percentage of SOL threshold may be introduced to achieve this.
No
We agree that specificity language such as "specify switching of synchronous BES tie lines" does not need to be included in R2. However, Operating Agreements cover activities other than switching, such as emergency assistance, switching coordination and communication, voltage/VAR support, system restoration, synchronization, etc. We suggest keeping R2, revising it to eliminate any duplication with other requirements and defining the minimum elements that

should be included in the agreement.
Yes
While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region. Such notification requirements should be established within each region based on the needs of the RC. Our experience in handling short and long term planned outages informs us that the timing and duration of outages will determine the allocation of time and other resource to assess impacts of the outages on the system. For short duration outages, a short term assessment is usually adequate as system conditions and topology are more predictable. The longer the duration of a planned outage, the less predictable are the system conditions and the more likely that other transmission facilities will be out of service during that period.
No
We do not support the revised standards. Our biggest concern is the removal of the requirement for TOP to operate within SOLs as stated in our response to Q#3. As stated in our previous comments we are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time." SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state, even before IROL violations become evident. If such upper bounds are to be ignored to enhance operating flexibility, the BES would be very vulnerable to instability, uncontrolled separation, or cascading outages upon the occurrence of subsequent contingencies. The 2003 blackout started off with an SOL violation, and is a good example of how a "localized" problem can propagate thru the interconnected network to become a widespread reliability problem. Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? We are also very concerned that R1/R2 in TOP-002 requires the TOP to assess potential exceedence of IROLs only but not SOLs. We feel strongly that R2 in TOP-002 should be revised so that it includes as part of the requirement, preclusion of operating in excess of any SOLs. Further, we believe that all SOLs should be respected in the planning time-frame and in real time with the exception of low likelihood or rare circumstances. WE believe the SDT may have misinterpreted our previous comments. By “system voltage may be depressed” we were saying the voltage may be lower than normal, we did not explicit state or imply that the depressed voltage will cause a collapse which appeared was the basis of the SDT’s response that we were talking about IROL - a subset of SOL. The argument that the TOP is required to calculate SOL but does not need to operate within all the time seems irrational. Operating with SOL all the time and correct exceedance within some defined time period is necessary to ensure reliability. The examples/rationale cited in the question asked in the previous comment form: “The SDT felt that requiring a TOP to operate within all SOLs could effectively reduce the TOPs operational flexibility by eliminating the TOP’s ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time.” was but one such situation. Load shedding to reduce equipment loading is often regarded by TOPs as an exception, i.e., load is not shed to correct a temporary exceedance of equipment rating or a potential exceedance of applicable equipment rating if a contingency were to occur. The rationale is simply to not shed load if exceedance of the facility’s continuous rating is expected to be temporary, or if a contingency were to occur then the expected loading will exceed the concerned equipment’s applicable rating since we do not shed load pre-contingency to avoid shedding load after a contingency has occurred. Operating within an SOL w/o having to shed load under some circumstances is clearly conveyed in our comments (underlined in our comments above). However, without the fundamental requirement to operating within SOL, it opens the door to various kinds of unreliable operating conditions. A first overloaded line, which trips because it loading is not corrected, will cause loading on other lines to increase. There is no certainty as to when and where loading on the remaining system will cease to cause additional tripping. Also, the absence of such a requirement begs the question on the need to: (a) Calculate SOL (FAC-014) in the first place. The SDT’s response that FAC-014 also requires the TOP to “communicate your SOLs to other entities so that they can respect your operational limits” seems a bit unfair since the TOP, as the SOL developer, does not itself need to respect the SOL but others do. And who are these “other entities” within the TOP area that need to respect the SOLs - The BA, GOP or the RC, while the TOP has the transmission reliability authority within its area and takes primary responsibility in transmission reliability (other than the RC who has a wide-area view and has the final authority)? (b) Perform day ahead analysis (TOP-002, R1) without requiring any follow-on actions if the analysis shows that SOLs will be exceeded. Developing SOLs and assessing if they will be exceeded would simply be an academic exercise. We are unable to determine how will not respecting SOLs and not having follow-on actions when SOLs are assessed to be exceeded contribute to reliability? (c) Report exceedances and corrective actions taken (TOP-001, R5). This serves no purpose if a TOP is not required to operate within SOLs. (2) TOP-002, R1 requires a TOP to assess next day operations and identify if any SOLs will be exceeded, and the actions related to SOL stops there. It is irresponsible for the TOP to not do anything such as adjusting outage plans and/or requesting adjustment to resource plans to arrive at operating conditions that will no cause SOLs to be exceeded. A requirement similar to that of R2 (for the IROL) should be developed. The only difference between them would be the need to prepare for load shedding when mitigating measures run out. (3) We noted that some VSLs are graded according to the number of occurrences. Please refer to the recent posting on the revised VSLs for 8 sets of standards, in which the VSLSDT made reference to the June 2008 FERC Order on VSL. In the Order, FERC provided a guideline (among others) that VSLs should not be determined by the number of occurrence. Specifically, FERC’s Guideline #4 stipulates that: Guideline 4 — VSLs should be based on a single violation, not on a cumulative number of violations (unless stated otherwise in the requirement). We suggest the SDT to

revise these VSLs accordingly.
Individual
Jason Shaver
American Transmission Company
No
The Standard states that the TOP render emergency assistance as requested and available. There are other standards (EOP-001, EOP-005, EOP-008) that require an entity to implement its emergency procedures. If an entity does not implement emergency procedures when required it would be a violation. Adding a sentence here that requires the requesting entity to implement its comparable emergency procedures would be redundant to the other Standards.
No
This requirement does not get into the specifics of what is required of the GOP other than to state that it shall coordinate its operations, which is an important function. TOP-003-1 requires specificity regarding data exchange which is a different and more specific scope than TOP-001-2 R4. The two requirements are very different in scope and are, therefore, not redundant.
No
Again, TOP-001-3 requires general coordination vs. TOP-004-3 has a very specific requirement regarding agreements that specify switching of synchronous BES tie lines. The two requirements are different in scope and are, therefore, not redundant.
No
We support the revised Standards. However, the questions asked do not reflect the current redlined versions of the Standards. We should be commenting on the version of the Standard that the drafting team wants to move forward with. The comment form and questions should match the current redlined version and not ask questions related to a proposed changed version.
Individual
Michael Ayotte
ITC Transmission
No
Generators have an important role in supporting BES reliability and that should be recognized. Taking a unit offline, particularly a must-run unit, should be coordinated with the TOP.
At a minimum, the Transmission Operator should report any SOL that has exceeded or is expected to exceed 30 minutes.
Yes
We would rather see a requirement that the RC specify the time period requirements for planned outages. While not opposed to having a uniform time requirement, we are not sure if it is necessary. If a time period is to be developed, it should consider voltage level, in other words more lead time for higher voltages. In addition, RC specified planned outage time period requirements should apply to transmission and generation outages.