

- Name (32 Responses)
- Organization (32 Responses)
- Group Name (23 Responses)
- Lead Contact (23 Responses)
- Contact Organization (23 Responses)
- IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (13 Responses)**
- Comments (55 Responses)
- Question 1 (35 Responses)
- Question 1 Comments (42 Responses)
- Question 2 (36 Responses)
- Question 2 Comments (42 Responses)
- Question 3 (36 Responses)
- Question 3 Comments (42 Responses)
- Question 4 (35 Responses)
- Question 4 Comments (42 Responses)
- Question 5 (37 Responses)
- Question 5 Comments (42 Responses)
- Question 6 (32 Responses)
- Question 6 Comments (42 Responses)
- Question 7 (34 Responses)
- Question 7 Comments (42 Responses)
- Question 8 (32 Responses)
- Question 8 Comments (42 Responses)
- Question 9 (33 Responses)
- Question 9 Comments (42 Responses)
- Question 10 (0 Responses)
- Question 10 Comments (42 Responses)

Individual
Ken Gardner
Alberta Electric System Operator
No
Please consider revising requirement R2 to use the proposed new definitions as follows: R2. Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3, each Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]
Individual
Tom Siegrist
EnerVision, Inc.
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating System
Yes
No
The last sentence in the definition is not needed, and should be removed. "The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation." is the "How" to meet the contingency reserve requirement, which does not belong in a definition. Suggest to remove this sentence.
No
There is no need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the Standard at all. If the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Pre-Reportable Contingency Event value, then the Standard is not explicit nor complete enough to place this obligation on the RSG.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
There isn't an appropriate technical justification for requiring a 500 MW threshold. If the justification is simply to obtain more data samples, a 1600 data request is more appropriate than an enforceable Standard. Suggest reverting back to the 80% threshold which has thus far, shown to provide for an

adequate level of reliability. The Standard can be simplified by replacing the existing requirements with ones that read: • recover from a Reportable Event within 15 minutes; • replenish reserves within 90 minutes.

Group

Arizona Public Service Company

Janet Smith, Regulatory Affairs Supervisor

Arizona Public Service Company

Yes

Yes

Yes

Yes

Yes

Yes

Yes

Yes

Yes

Individual

John Tolo

Tucson Electric Power

Yes

Yes

Yes

Yes

Yes

Yes

Yes

Yes

Yes

very helpful

Individual
Rich Hydzik
Avista
No
The changes to the definitions add clarity, but ambiguity still exists around one phrase. What constitutes an "unexpected change to the responsible entity's ACE?" Does this mean that there is no human action when the ACE change occurs? Does this mean that a human action to change a Net Interchange value in the ACE equation is "unexpected" when it is due some force majeure condition? Clarity around this issue is necessary to prevent Balancing Authorities (BA) from merely adjusting their Net Schedule Interchange value to correct ACE and passing the problem on to another BA. If transmission curtailments and unexpected adjustments to e-tags are acceptable events to deploy contingency reserve and are considered "Sudden Loss of Generation" under BAL-002-2, this needs to be explicitly stated. If transmission curtailments and unexpected adjustments to e-tags are NOT acceptable events to deploy contingency reserve and are NOT considered "Sudden Loss of Generation" under BAL-002-2, this needs to be explicitly stated. The Background Document discusses frequency deviations on Page 4 under "Balancing Contingency Event." This seems to preclude any human action to alter Net Scheduled Interchange as a "Balancing Contingency Event."
Yes
Yes
The assumption is made that algebraic sum of the ACE's is as follows: Reserve Sharing Group Reporting ACE = ACE(BA1) + ACE(BA2) + ACE(BA3) + .... An example calculation would be helpful and provide clarity.
Yes
This language clarifies that when in an Energy Alert 2 or 3, the BA is using all available reserves to maintain ACE.
Yes
Yes
Yes
Yes
Yes
I can support this draft standard with the clarifications requested in Question #1 above.
Individual
Nazra Gladu
Manitoba Hydro
Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
No comment.

Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
No comment.
Although Manitoba Hydro is in support of this standard, we have the following clarifying comments: (1) Definitions, Reportable Balancing Contingency Event – there is no definition within the standard or Glossary as to what ‘EMS scan rate data’ is. (2) Definitions, Contingency Event Recovery Period – the definition does not clearly define exactly when the Contingency Event Recovery Period begins. As written, the definition seems to indicate that this period begins at two different times (i) when the resource output begins to decline and (ii) in the first one minute interval of a Balancing Contingency Event. Please clarify. (3) Section D, Compliance, 1.1 – the paraphrased definition of ‘Compliance Enforcement Authority’ from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (4) 1. (Proposed) Effective Date in both Standard and Implementation Plan - remove the “ ” following the word ‘Trustees’ because it is not defined this way in the Glossary of Terms. (5) R1 - as written, R1 requires that the Responsible Entity demonstrate that ACE was returned to a certain value. The demonstrate aspect of the requirement seems more of a measure than a requirement. In other words, the requirement should be that the Responsible Entity return the ACE to a certain value, the measure is that they provide evidence to demonstrate that they did so. (6) R1, R2 – both ‘MSSC’ and ‘Most Severe Single Contingency (MSSC)’ are used throughout the standard. The words ‘Most Severe Single Contingency (MSSC)’ should be used at the first instance and then the acronym ‘MSSC’ for all instances thereafter. (7) R2 – some of the terminology appears to be incorrect within this requirement. Is ‘Disturbance Recovery Period’ meant to be ‘Contingency Event Recovery Period’? Is ‘Contingency Reserve Recovery Period’ meant to be ‘Contingency Reserve Restoration Period’? (8) M1 – the word ‘including’ should be replaced with ‘as well as’ if the ‘additional documentation’ that needs to be provided is in addition to the CR Form 1, not that the additional documentation forms part of the CR Form 1. (9) VRF/VSL - capitalize ‘bulk electric system’ in both the High Risk Requirement and Medium Risk Requirement sections. (10) VSL, R1 – the language of the VSL does not track the language of the requirement or measure. The VSL refers to ‘recovering from an event’ while the requirement refers to returning ACE to a certain level. (11) VSL, R2 – the language of the VSL does not track the language of the requirement or measure. The VSL refers to calendar quarters, while the requirement and measure do not.
Group
Salt River Project
Bob Steiger
Electric Reliability Compliance
Yes
Yes
This standard is a big improvement over the existing standard because it provides much needed formal definitions of many terms that are used but not currently defined in BAL-002-1, the definition of Contingency Event, Contingency Reserve and MSSC being three of them.
Yes
Same comment as for #2.
Yes

Yes
Yes
Yes
Yes
Yes
Group
PacifiCorp
Ryan Millard
PacifiCorp
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Rich Salgo
NV Energy
No
Inclusion of "Sudden loss of a known load" is at odds with the Contingency Reserve definition, especially in light of the fact that loss of load cause ACE to increase (become more positive). In other words, why would one carry reserves to handle a decrease in load? It's illogical. What the SDT may be trying to reference is the use of interruptible load as a type or reserve. As such, load should not be in the Contingency Event definition.
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
The Reportable Balancing Contingency Event definition lacks clarity. Are we to choose the higher of 500 MW vs. 80% of the MSSC or the lower of 500 MW vs. 80% of the MSSC? Seems like the measurement should be the higher of the two. 2. While I think I understand the goal of R1, to return ACE to zero neglecting other contingency events within the recovery period, the wording is very confusing. Expect misapplication of the standard with the existing wording. I suggest, for bullet #2: • Its Pre-Reportable Contingency Event ACE, (if its Pre-Reportable Contingency Event ACE was negative), o less the Balancing Contingency Events' magnitude summation for all subsequent events occurring within the Contingency Event Recovery Period, and o If the contingency event is greater than MSSC, further reduce the ACE recovery magnitude by difference between the Responsible Entity's MSSC and the uncompleted Balancing Contingency Events' magnitude summation.
Group
MRO NERC Standards Review Forum
Russel Mountjoy-Secretary
MRO
No
The presently approved NERC definition for contingency seems adequate for this standard. If the DCS definition will not be used any longer, recommend the team retire it from the NERC glossary.
Yes
No
All that's needed is a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
No
This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. Please clarify. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies they carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. Please clarify. The last most significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to

embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. Is the SDT stating that recovery is needed to recover to zero or MSSC? We believe the way a way to achieve the Commissions directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.

No

We believe the requirement itself is inappropriate, so any VRF is unnecessary.

Yes

No

Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.

No

There first needs to be agreement on the requirements before there is concurrence with the background document.

Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL are crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives. Recommend that each interconnection has a different MW level, due to the sheer size of each interconnection. As an Eastern Interconnection entity, we recommend 900 MW vise 500 MWs. The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. Our recommendations are:

- Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes).
- Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency.
- Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation.
- The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA's performance approaches non-compliance. The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority. The drafting team is proposing to continue to use only ACE under Requirement R1 as the measure of reliability in the determination



of Balancing Authority or RSG compliance. As has been seen in actual operation, the current methodology can lead to and has caused RC directives to drop load when there was not a reliability issue, defined as a frequency concern or transmission line loading issue. ACE is not a primary measure of reliability, only equity. To remedy this deficiency in the proposed standard, the drafting team should utilize the BAAL limit as a more appropriate measure of response to the sudden loss of generation, not pre-event ACE or zero, whichever is lower. As proposed by the NSRF, this does not do away with DCS as originally proposed under BAAL but would change the measure of compliance in the DCS process to a more appropriate, reliability based measure. The NSRF is also not proposing to change the 15-minute period in BAL-002 for a reportable event with this modification.

Individual

Anthony Jablonski

ReliabilityFirst

No

a. ReliabilityFirst recommends removing any references to “an Energy Emergency Alert Level 2 or Level 3” since these are not defined terms (Energy Emergency Alert Levels are only noted in Attachment 1, EOP-002-3). ReliabilityFirst believes the BAL-002-2 should stand on its own merit and not rely on conditions within an attachment within another standard. For example, if the Energy Emergency Alert levels designations ever change in the future, this has the potential to have an impact on the intent of the BAL-002-2 standard. For consideration, ReliabilityFirst recommends defining the alert levels within the standard itself as an attachment, hence not relying on another standard for these conditions.

No

The VSLs for Requirement R2 references “each calendar quarter” while the actual requirement R2 does not require maintaining an amount of Contingency Reserve at least equal to its Most Severe Single Contingency on a quarterly basis. Also, the lower VSL starts with an entity being deficient for more than five hours. This poses a gap; if for example, an entity was deficient between one and four hours. ReliabilityFirst recommends restructuring the VSLs, to be consistent with the language in the requirement, as follows (this is an example of a Lower VSL); “The Responsible Entity maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency but its Contingency Reserve was deficient for less than or equal to 15 hours.”

ReliabilityFirst votes in the negative for this standards and offers the following for consideration: 1. Definition of Reportable Balancing Contingency Event: ReliabilityFirst does not agree with the inclusion of last sentence (i.e., The 80% threshold may be reduced upon written notification to the Regional Entity) within the definition. As written, the definition infers that there is an expectation that a Regional Entity may have to make a determination on whether to accept a reduction in the 80% threshold based upon the written notification. This is troublesome in two ways. One, this is written more like a requirement, though it is actually contained within a definition. Two, standards should not be written with expectation placed upon a non-registered entity (i.e., the Regional Entity). ReliabilityFirst recommends removing this last sentence and any reference to the Regional Entity. 2. Applicability Section - ReliabilityFirst recommends removing the paragraph stating “Applicability is determined on an individual event basis...” from the Applicability section. The Applicability section should state the functional entity that is required to comply with the standard and the requirements should state any conditions necessary to achieve the action or outcome.

Individual

Joe Tarantino

SMUD

Yes
Yes
Yes
Yes
Yes
Individual
Jim Cyrulewski
JDRJC Associates LLC
Agree
Midwest ISO
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
No
We would suggest incorporating the concept of an unexpected event with the loss itself rather than tying it to the change in ACE. For example in Subsection A, we would propose: 'Sudden, unexpected loss of generation...' Similar changes need to be made to Subsections B and C. Also, there is a timing element associated with Subsection B which could cause conflict with the wording in B. Requiring a sudden loss of import by the loss of a transmission element, implies that the loss of import would be sudden. It may or may not be. It depends on when the loss is reflected in schedules. Additionally, an entity may not know that the loss is due to a loss of transmission. We would suggest: 'Sudden, unexpected loss of an import that causes a change to the responsible entity's ACE.' In Subsection C we suggest: 'Sudden unexpected loss of a known load...' The term 'responsible entity' is not capitalized in the definition but is in the standard. Should it be in the definition?
No
As written there is no distinction as to whether 'unloaded generation' is on-line or off-line generation. Which is it, or is it both? Additional clarification here would be helpful.
No
Do you need to add '...at the time of the measurement' at the end of the definition?
Yes
Yes
Yes
Yes



referenced or used in the standard at all. On the other hand, if the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Pre-Reportable Contingency Event value, then the standard is not explicit or complete to place this obligation on the RSG.

Yes

Yes

Yes

Yes

Yes

Yes

We will support this standard, however please note the concerns expressed under Q2 and Q3, above, namely: a. The last sentence in the definition for Contingency Reserve, and b. The need to define the term Reserve Sharing Group Reporting ACE (or the lack of explicit requirement for RSG to meet the DCS requirement).

Individual

Howard F. Illian

Energy Mark, Inc.

No

The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is.

Yes

No

The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is.

Yes

No

I believe that this requirement falls under Paragraph 81 and should not be in the standard.

Yes

Yes

Yes

Yes

The definition of "Pre-reportable Contingency Event ACE Value" should be modified as follows: The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is. I would strongly suggest that the wording for Requirement 1 should be modified to read as follows: R1. Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its Reportable ACE to: [Violation Risk Factor: Medium][Time Horizon: Real-time Operations] • Zero. (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero): o less the

sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reportable ACE within the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reportable ACE within the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.

Group

SERC OC Standards Review Group

Stuart Goza

Tennessee Valley Authority

Yes

Yes

No

The definition should only include the BAs that were participating in the event.

Yes

No

This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe a way to achieve the Commissions directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. We agree with the principle of a BA maintaining contingency reserves to respond to its MSSC. However, as R2 is currently proposed it puts the BA at risk if contingency reserves fall below its MSSC for any single sampling period. Indeed, as stated it puts a BA with a 2 second sampling interval at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the Measures and VSL, we believe that the requirement needs to stand on its own and that the specifying language should be included in R2 itself.

No

It is difficult to agree with the VRF's while disagreeing with the standard as proposed.
Yes
No
Requirement 1 should not be an event by event obligation. A quarterly average measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
No
The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." We disagree with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. We believe that the Commission clearly did not intend that any event that causes a frequency deviation, not matter how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500 MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample. We question whether this is appropriate and believe that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method. We suggest that additional details be provided in the Background Document relating to the methodology for development of the reporting thresholds.
There is an embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. We appreciate the SDT's goal of drafting a continent-wide standard but disagree with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, we believe that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500 MW as an example, a loss of 500 MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500 MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. We believe that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection. We respectfully suggest that the SDT give due consideration to redefining a Balancing Contingency Event and Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. We believe this is one approach that could satisfy the directive set forth in Order 693. In R1 and R2, delete the language related to an RE under an Energy Emergency Alert Level 2 or Level 3, for 2 reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. E.g. an EEA in effect for a BA in Florida should not be a

consideration for the performance of a contingent RE anywhere in the EI. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE – this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The “Applicability” section clearly states that the standard does not apply to an RE under an EEA. Words could be added to R1 and R2 to clarify that the contingent RE is also the RE experiencing an EEA but a better solution is to simply delete the EEA related language from R1 and R2, Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the “hard” criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection – wouldn’t this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. We suggest that a successful response by the RE would return ACE to the lesser of 0 or its real time BAAL low limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero) and similarly – ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL low limit (if its Pre-Reportable Contingency Event ACE was negative). If the interconnection frequency is high – why require a BA to increase generation more than is necessary to meet its BAAL low limit? If interconnection frequency is low, the BAAL low limit as well as the zero or pre-contingent ACE rule would still apply. These comments were also supported by Ron Carlsen with Southern Company. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.

Group

seattle city light

paul haase

seattle city light

No

Seattle City Light considers the definition of Balancing Contingency Event proposed in this draft of BAL-002-2 to be incomplete in that it does not recognize the failure of a unit to start as an “event.” Seattle recommends revising the definition to read: “A.a.i. Unit Tripping or failure to start at the scheduled time.”

Yes

Yes

Note there are differing reference to Regulating Reserve Sharing Group and Reserve Sharing Group BAL-001-2 and BAL-002-2. Seattle City Light recommends consistent terminology across the standards.

Yes

This standard is an improvement over the existing BAL-002 because it clarifies the requirements for a Balancing Authority or Reserve Sharing Group regarding Contingency Reserve requirements during Energy Emergency Alerts.

No

Seattle City Light finds Requirement R2 and Measure M2 to lack specificity as to what level of performance is required for compliance, and recommends the following changes: “R2. Each Responsible Entity shall maintain an amount of Contingency Reserve such that its clock-minute average of Contingency Reserves is equal or greater than the Most Severe Single Contingency except during the Disturbance Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert 2 or 3.” “M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, Energy Management System logs, software programs, or other evidence (either hard copy or electronic format) to demonstrate compliance with Requirement R2.”

Yes

Yes

Yes
Seattle City Light supports the general concepts of this draft of BAL-002-2, but as with BAL-001-2, Seattle thinks this draft needs more work and should not be implemented as currently written. It appears to have been rushed. Several specific recommendations for changes have been noted above. However, at least until the Guidelines document is available that details how this Standard will work in conjunction with other BAL Standards, Seattle cannot support this draft.
Individual
Kenneth A Goldsmith
Alliant Energy
Agree
MRO NSRF
Group
PJM Interconnection, LLC
Stephanie Monzon
Stephanie Monzon
Yes
Yes
No
The definition should only include the BA's participating in the event.
No
PJM agrees with the principle of a BA maintaining contingency reserves to respond to its MSSC but believe this requirement would have negative unintended consequences. Reserves should be used when there is a reliability need that may or may not be caused by the loss of a resource. This requirement encourages BA's to withhold deployment of contingency reserves except for DCS reportable disturbances. For example, if a BA's ACE is dragging into the top of the hour, along with Interconnection frequency, due to schedule changes and slow unit response, this requirement incentivizes the BA to withhold deploying reserves. If a BA is approaching an IROL that could be mitigated by deploying contingency reserves, this requirement penalizes the BA for doing so, even though the result would benefit the Interconnection. Even if PJM agreed with the proposed R2, which we do not, as written it puts the BA at risk if contingency reserves fall below its MSSC for any single sampling period. Indeed, as stated it puts a BA with a 2 second sampling interval at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the Measures, specifically M2, PJM believes that the requirement needs to stand on its own and that the specifying language should be included in R2 itself. DCS performance in North America has been greatly improved compared to what was considered adequate performance under Policy 1. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe a way to achieve the Commission's directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process, as was a directive in 693), NERC could add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data".
Yes
No



It is difficult to agree with the VSL's while disagreeing with the standard as proposed.
No
<p>The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." PJM disagrees with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. PJM believes that the Commission clearly did not intend that any event that causes a frequency deviation, not matter how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample, skewing the results. PJM believes that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method.</p>
<p>In R1 and R2, delete the language related to a Responsible Entity under an Energy Emergency Alert Level 2 or Level 3, for the following reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE – this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection – wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. PJM appreciates the SDT's goal of drafting a continent-wide standard but disagrees with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, PJM believes that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500MW as an example, a loss of 500MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. PJM believes that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared annually by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection (ALR1-12 Assessment). As previously stated, PJM respectfully suggests that the SDT give due consideration to redefining a Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. PJM believes this is one approach that could satisfy the directive set forth in Order 693.</p>
Individual
Andrew Gallo
City of Austin dba Austin Energy
Agree
ERCOT



Yes
Yes
There isn't an appropriate technical justification for requiring a 500 MW threshold. If the justification is simply to obtain more data samples, a 1600 data request is more appropriate than an enforceable Standard. Suggest reverting back to the 80% threshold which has thus far, shown to provide for an adequate level of reliability. The Standard can be simplified by replacing the existing requirements with ones that read: • recover from a Reportable Event within 15 minutes; • replenish reserves within 90 minutes. As written, the Standard is overly complex.
Individual
Thad Ness
American Electric Power
Yes
No
It is not clear exactly what "other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3)" refers to.
Yes
No
Please see our response to Q2 in regards to the definition of Contingency Reserve. AEP disagrees with the second half of R1 where it begins with "or... Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative)..." . The language provided in this section and its sub-bullets are extremely confusing. It appears that the intent is to set an expectation for recovering from multiple contingency events, however the language provided is unnecessarily complex and will likely confuse those responsible for meeting the requirements.
Yes
Yes
Yes
Yes
No
It is unclear whether or not the guidance document will eventually become a part of the officially posted standard (in an appendix for example).
In addition to the comments provided to the earlier questions above, AEP offers the following additional comments for consideration. AEP disagrees with the latest proposed definition of "Pre-Reportable Contingency Event ACE Value", which has been made ambiguous by the most recent modifications. What is the intent of the drafting team in modifying the definition in this way? If this definition were to be used, new tools would likely need to be developed in order to calculate the value in this manner, as the operators would now be required to continuously calculate the ACE value based on this new definition. The definition for, and application of, Contingency Event Recovery Period is unnecessarily complex, confusing, and likely unpractical in its application. For example, if a unit was taken out of service due to a controlled shut-down, the Real Time Operator's most pressing responsibility is balancing load and generation. Requiring this person to use the proposed methodology to determine exactly the contingency event recovery period began would distract the Real Time Operator from their core balancing responsibilities. Rather than take this approach, we

recommend retaining the existing way of determining when the recovery period begins, which is a more straightforward and reasonable approach. In addition, the definitions for Contingency Event Recovery Period and Contingency Reserve Restoration Period are quite similar and would most likely prove confusing to industry in their application. Taking a conditional-based approach across multiple standards does not serve the reliability of the bulk electric system, as it takes a straightforward concept, overly complicates it, and distracts Real Time Operators from the core reliability objectives.

Group

Duke Energy

Greg Rowland

Duke Energy

No

• The definition is too broad. Using the phrase “or any series of such otherwise single events” leaves much open to interpretation. In many cases it will not be clear when the 15-minute clock has been triggered. • Regarding Subsection “C.”, it is also not clear what is meant by the “sudden loss of a known load used as a resource”. Is the team referring to an interruptible load resource, fully loaded and counted on for provision of contingency reserve? If so, would the sudden loss of the resource mean that the load is inadvertently interrupted causing high ACE? We’re not aware of a proven reliability risk that warrants a 15-minute recovery period from a high ACE. Or, is the team referring to an interruptible load resource already implemented (curtailed) for a first contingency, and then somehow losing the curtailment capability where the resource fully loads again causing low ACE (second contingency)? If so, has any such event ever been documented to warrant placing a statement subject to interpretation in the Standard? • Duke Energy suggests striking Subsection “C.”, as loss of any load is covered under the BAAL in BAL-001-2. • Based upon the above, Duke Energy suggests revising the definition to – “Balancing Contingency Event: Any single event described in Subsection (A) or (B) below, or any combination of those events occurring within less than one minute.” Duke Energy suggests revising Subsection “A.b” to read “And, that causes an unexpected negative change to the responsible entity’s ACE”, and suggests revising Subsection “B” to state “Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected negative change to the responsible entity’s ACE.” Both changes are suggested to clarify that this standard is applicable to the loss of resource causing an unexpected drop in ACE. To the extent that Subsection “C” is retained, Duke Energy suggests a similar revision to insert the word “negative”.

No

We would be in agreement except that it includes the term “Balancing Contingency Event”, and we would need our above suggested changes made to that definition to be in agreement here.

No

Only BA’s participating in response to an event should be included in the Reserve Sharing Group Reporting ACE calculation. As we commented on BAL-001-2, ACE should be fully defined in a manner where Reporting ACE can be defined simply as the “The scan rate values of a Balancing Authority’s ACE”.

Yes

We agree with the change to R1 to recognize emergency operations as long as the BAAL is implemented in BAL-001-2, as it is the only viable standard for measuring real-time performance and the BA’s impact on Interconnection frequency during such operation. Duke Energy agrees that the proposed language in this standard will allow the BA to utilize its contingency reserves to continue to serve load under an Energy Emergency Alert Level 2 or Level 3 while remaining compliant to BAL-002; however under what circumstances, if any, should the Balancing Authority shed firm load as a last resort to ensure that it remains compliant to Requirement R1 under normal operations? In our opinion, the inability of a Balancing Authority to meet the 15-minute DCS compliance threshold does not in itself represent a reliability issue. There are cases in the off-peak times especially where the recovery is detrimental to Interconnection frequency. Some of the revisions in BAL-002-2 blur the clear and well-established criteria of what triggers the DCS event. Too much is left up to after-the fact compliance scrutiny, and operators need unquestionable guidance on this matter. Also, in the definition of Contingency Reserve, add the word “NERC” before the word “contingency” for clarity.

No

Requirement R1 and R2 could provide a consistent continent-wide Contingency Reserve policy if the definition of Balancing Contingency Event provided a "bright line" to the industry on what events would be applicable to the determination of MSSC; we believe that Subsection "C." of that definition should be deleted, per our comment under question #1 above, and if the R2 allowed for other use of Contingency Reserves. Requirement 2 refers to "Disturbance Recovery Period" and "Contingency Reserve Recovery Period" which are no longer defined. Duke Energy would suggest the following change: "Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3, each Responsible Entity shall maintain an hourly average amount of Contingency Reserve at least equal to its Most Severe Single Contingency." Language in Requirement R2 should also recognize that Contingency Reserves may be used from time to time to aid in balancing aside from the loss of resource – today such use takes places and does not impact compliance under DCS. Measure M2 requires that the Contingency Reserve averaged over each clock hour is greater than or equal to the amounts identified in Requirement 2 – however, as the amounts identified in Requirement R2 are allowed to be less than MSSC, it is not clear why the language at the end places an exception only on the 105-minute combined recovery and restoration period, and not on any period such resources may be utilized under an EEA2 or EEA3. Duke Energy would suggest modifying Measure M2 to read at the end "except during an Energy Emergency Alert Level 2 or Level 3, or within the first 105 minutes following an event requiring the activation of Contingency Reserve." Though an hourly average is proposed, it is not practical for a BA to track its Contingency Reserves in a manner where it would make the choice to increase its Contingency Reserves above the MSSC if it happened to drop below its MSSC for some time in the same hour – it is an unnecessary activity to bring into real-time operations. Also, we believe the Standard Drafting Team should carefully check to make certain that these new definitions don't impact other existing definitions. Though suggestions have been provided, Duke Energy does not support the adoption of Requirement R2 and agrees with the comments provided by MISO. Performance under the existing BAL-002 has been stellar without the need for an additional requirement to track Contingency Reserves to the extent prescribed. The current DCS is a very effective results-based standard. The existence of a requirement such as R2 will result in inefficient utilization of resources, increased costs, inaccurate representation of resource capability, and other negative consequences with no benefit to reliability.

No

We can't agree, due to the current lack of clarity in the requirements.

Yes

No

We can't agree, due to the current lack of clarity in the requirements.

• As the BAAL proposed in BAL-001-2 will address the loss of any resource, or any other change in ACE causing a Balancing Authority to exceed its BAAL, it could be argued that there is no reliability need to retain DCS. In 2007, the NERC Operating Committee supported the adoption of the BAAL and a subsequent field trial of operating without DCS to determine if the Standard was still needed. Until more experience is gained under the BAAL, Duke Energy supports having a Standard driving a Balancing Authority to address the largest of its events as it does today, however we see no reliability need to expand BAL-002 beyond the simple concept of measuring the recovery to the largest of the BA's resource losses – 80% or greater of the MSSC, and limited to MSSC, where the applicable events are clearly understood by the operator. Duke Energy disagrees with applying compliance and associated compliance reporting on an event-by-event basis, rather than allowing the quarterly reporting currently provided under BAL-002. The measures for compliance should recognize that no technical basis has been provided to support the 15-minute recovery required under Requirement R1 – compliance to a line drawn in the sand can be measured on a quarterly basis similar to today, as real-time reliability needs will be met by the BA being held to compliance under BAAL. • Duke Energy disagrees with the definition of "Reportable Balancing Contingency Event". Given that all resource losses will be captured by the BAAL under BAL-001-2, that there is no basis for using 500 MW as a baseline for reporting, and that there has not been a demonstrated reliability need to move away from our current reporting criteria of 80% or greater of the MSSC, Duke Energy does not support the

inclusion of the 500 MW threshold in the definition.. We believe that BAAL 30-minute response covers all events, and DCS action is a 15-minute response intended to address large events. We agree with MISO's comment that currently DCS is measured quarterly, and the proposed Requirement R1 creates an unnecessary event-by-event compliance evaluation. Adding the 500 MW threshold and multi-contingent event expectation is excessive, with no benefit to reliability. • Duke Energy believes that Reserve Sharing Group should have the flexibility to calculate a group ACE rather than just taking the algebraic sum of all the BA ACEs.

Individual

John Seelke

Public Service Enterprise Group

Agree

PJm Interconnection

Group

DTE Electric

Kent Kujala

DTE Electric

Agree

MISO

Individual

Keith Morisette

Tacoma Power

No

Tacoma Power is unfamiliar with the phrase, "... known load used as a resource ..." We believe the industry cannot interpret these words consistently. Instead, we suggest using the phrase, "... interruptible load claimed as available reserves ...," which is Tacoma Power's interpretation.

Yes

Yes

Yes

Yes

Yes

Yes

No

Tacoma Power does not understand - all levels state that the Responsible Entity recovered from the event, yet they recovered to less than 100% of the required recovery. How can it be "recovered" without reaching 100% in every case? Instead, we suggest that the VSLs recognize that the Responsible Entity "partially recovered" from the event.

Yes

Tacoma Power appreciates the opportunity to provide comments. We cannot support this draft of the standard because we are unfamiliar with the phrase, "... known load used as a resource ..." in the definition of a Balancing Contingency Event. Therefore, this phrase must be defined or replaced so that there is no confusion within the industry and compliance authorities. We suggest using the phrase, "... interruptible load claimed as available reserves ...," which is Tacoma Power's interpretation. In addition, the VSLs are very confusing. All levels state that the Responsible Entity

recovered from the event, yet they recovered to less than 100% of the required recovery. How can it be "recovered" without reaching 100%? Instead, we suggest that the VSLs recognize that the Responsible Entity "partially recovered" from the event.

Individual

Don Jones

Texas Reliability Entity

Yes

Definition of "Balancing Contingency Event" is slightly different in Implementation Plan as compared to Standard (A.a.iii. Facility vs Facilities, B. Import vs import...). Definition of "Reportable Balancing Contingency Event" is different in Implementation plan as compared to Standard (Implementation Plan does not include phrase "The 80% threshold may be reduced upon written notification to the Regional Entity.") The Applicability section in the Implementation Plan is also different than the Standard.

Yes

The Contingency Reserve definition should mention a Reserve Sharing Group in addition to a BA.

Yes

Yes

R2- Disturbance Recovery Period is not defined and should be changed to Contingency Event Recovery Period.

Yes

A Responsible Entity may have an internal Contingency Reserve policy that is different than the proposed language in R2. While we understand the R2 states the minimum Contingency Reserve amount, should R2 be re-worded to state that each Responsible Entity shall maintain an amount of Contingency Reserve as least equal to its Most Severe Single Contingency or an amount per its Contingency Reserve policy, whichever is larger? Ex. The MSSC in ERCOT is 1375 MW, but the required minimum responsive reserve is 2300 MW, which is the amount necessary to maintain adequate primary frequency response to meet the intent of the BAL-003 standard.

Yes

Yes

No

1) R1 VSL- At what point is the ACE measured in order to determine the % of required recovery. We assume it is the lowest ACE value measured during the one-minute period for the Balancing Contingency Event, but this should be clarified. 2) R2 VSL – A deficiency less than 5 hours is not covered by the VSL. If the intent is to allow a certain amount of deficiency without penalty, that should be clearly stated in the requirement and not implied in the VSL. 3) R2 VSL – Five hours in a calendar quarter of not having sufficient Contingency Reserves seems too long, especially since Contingency Event Recovery Periods and EEAs are excluded. We would recommend a shorter time frame, e.g. 0-3 hours for lower VSL, 3-5 for moderate VSL, 5-10 for high VSL, and >10 for severe VSL. Also, the time frame for each VSL level needs to state if it is cumulative or on a per-event basis (we assume it is cumulative but it should be explicitly stated).

No

The equations and methodology on CR Form 1 seem flawed. The recovery requirement in R1 is based on ACE, but the calculations in CR Form 1 are based on the MW lost. We believe the equations in CR Form 1 and the Background Document should be modified to incorporate the elements of the ACE equation into the calculations (i.e. frequency deviation and frequency bias in particular). For example, a recent unit trip of 1300 MW occurred. Based on the frequency deviation, the lowest ACE during the one-minute event period was -1900 MW. The language of the requirement and the CR Form 1 should reflect the recovery of the ACE (1900 MW) rather than the MW lost (1300 MW) in this case.

1) In ERCOT, we have an existing process in place to analyze unit trips greater than 500MW.

However, other interconnections may find it overly burdensome to analyze these unit trips based on their current size and loads. 2) R1, as stated, is an event-by-event obligation. A failure to recover for one event would constitute a violation, even though the Responsible Entity may have performed well for the remainder of the period. Is this the intent of the SDT? Would the SDT consider another measure, such as evaluation of multiple events on a quarterly basis? 3) Does the SDT intend to retire the existing "Disturbance Control Standard" definition? Do you need to modify definition of "Reserve Sharing Group" to not reflect usage of "Disturbance Control Performance"? 4) The Reserve Sharing Group Reporting ACE definition is different here than the Regulation Reserve Sharing Group Reporting ACE definition provided in BAL-001-2, which is correct? (i.e. Does not have "at the time of measurement" as last part of sentence). 5) How do you calculate a Reserve Sharing Group Pre-Reportable Contingency Event ACE Value? We assume it is the algebraic sum of the ACEs of the BAs that make up the Reserve Sharing Group, but it may need to be explicitly stated.

Individual

Oliver Burke

Entergy Services, Inc. (Transmission)

Agree

SERC OC Standards Review Group

Individual

Brian Murphy

NextEra Energy

Empty table rows for additional responses.

Have the option also calculate ACE using the following formula:  $ACE = (NIA - NIS) - 10B (FA - FS) - IME$

Individual

Robert Blohm

Keen Resources Ltd.

Yes

No



The definition is left vague, to enable "double counting" of reserve types. It is a definition not of reserve "allocated" to contingency/restoration, but of reserve that is "usable" for contingency/restoration and which includes the two other defined types of reserve, Frequency Responsive and Regulating. This distinction, between "usable" and "allocated" remains notoriously unclear in this definition, and in apparent contradiction to the provision against double-counting of reserve in the "Guidance Document" currently in preparation. To make the distinction clear, and that occasional "double counting" of reserve types is specifically being allowed by the BAL performance standards, this definition needs to be broken into two definitions. The term "Contingency Reserve" defined in the current definition should be changed to "Reserve Usable for Contingencies" which should be the term used in requirement R2. A second, clear definition of "Contingency Reserve" should be made for use in the Guidance Document, as reserve "allocated" for contingency/restoration, and the term "Contingency Reserve" should thereby be made clearly usable in that document's admonition against double counting of the three types of reserve: Frequency Responsive, Regulating, and Contingency.

Yes

No

You mean not "possible issues" but "possible issues related to EOP standards". Otherwise, see answer to question 2 about other issues.

No

As explained in my Comment to Question 2, the commonly used term "Contingency Reserve" needs to be unpacked into two terms: "Contingency Reserve" (to be used in the "Guidance Document" currently being prepared) and "Reserve Usable for Contingencies" (to be used in this standard instead of "Contingency Reserve"). The FERC Directive 693 did not identify and sort out this ambiguity and called simply for a requirement of undifferentiated "response" to a contingency, without distinguishing between the three intrinsic "types" of response, namely Frequency Response, Regulating Response, and Contingency Response, except to designate the "objective"/cause of the Response. All three types of response can meet that objective. The FERC Directive then sought to expand the definition of Contingency Reserve to include demand-side resources, and to set the requirement of a quantity of "Contingency Reserve", without specifying "Contingency Reserve" as any particular reserve type. So, yes, R2 does address the FERC Directive, but the FERC Directive is itself inadequate for failing to make the all-important distinction between type of reserve, and usability of different reserve types to meet a single reliability objective which would be some generalized "Responding" to a "Contingency" without specifying the "type" of response which distinguishes reserve types. Rather than simply "address" a technically uninformed FERC Directive, NERC should in its superior reliability wisdom/competence seek to improve upon the FERC Directive and establish the precedent that FERC takes technical direction from NERC, not the other way around and without opposing or contradicting FERC.

Yes

Yes

Yes

No

The definition of "Best ACE" is unclear as: the "most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)". The meaning of "if any" is specified only in the attached spreadsheet that makes "claiming" such a subsequent event "optional" to the BA. In other words, a BA will not claim a subsequent event that makes the BA's compliance worse. The purpose of this definition of "Best ACE" is to prevent R1's sanctioning a BA's avoiding non-compliance due to insufficient reserve, by incurring a subsequent contingency within the recovery period to reduce the BA's recovery requirement. By this definition of "Best ACE" a BA will not claim a subsequent event that makes the BA's compliance worse. A clearer alternative definition of "Best ACE", that does not require the "optionality" obscurely lodged in the spreadsheet and that would harmonize with the needed change to the R1 wording that I show in my Comment to Question 10,

would be "the least negative value if there are no positive values, or the most positive value of any positive values, among the values of ACE occurring during the recovery period, unless it is the ACE to which the addition of any subsequent events that occurred prior to or concurrently with it results in a value that is the least negative value if there are no positive values, or the most positive value of any positive values, among all such resultant values and the other ACE values during the recovery period."

The wording of the recovery target ACE in Requirement 1 needs to be replaced as follows: "less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur WITHIN THE CONTINGENCY EVENT RECOVERY PERIOD [caps mine]" should be replaced by "less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur AT THE MOMENT OF RECOVERY (OR NEAREST-RECOVERY), or beforehand [caps mine]". Otherwise, by containing the word "all" in the selected wording, R1 sanctions a BA's avoiding non-compliance due to insufficient reserve, by incurring a subsequent contingency within the recovery period to reduce the BA's recovery requirement. Furthermore, the current R1 definition contradicts the definition of "Best ACE" contained in the Background Document that was intended to preempt such BA behavior by defining "Best ACE" as: the "most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)". The meaning of "if any" is specified only in the attached spreadsheet that makes "claiming" such a subsequent event "optional" to the BA. In other words, a BA will not claim a subsequent event that makes the BA's compliance worse. A clearer alternative definition of "Best ACE", that does not require the "optionality" obscurely lodged in the spreadsheet and that would harmonize with the needed change to the R1 wording, would be "the least negative value if there are no positive values, or the most positive value of any positive values, among the values of ACE occurring during the recovery period, unless it is the ACE to which the addition of any subsequent events that occurred prior to or concurrently with it results in a value that is the least negative value if there are no positive values, or the most positive value of any positive values, among all such resultant values and the other ACE values during the recovery period."

Group

Iberdrola USA

John Allen

Rochester Gas & Electric

Agree

NPCC

Individual

Steven Wallace

Seminole Electric Cooperative, Inc.

Yes

Yes

No

As written, it arbitrarily precludes the calculation of an RSG ACE for an entire RSG based upon the aggregate frequency bias, and the RSG participants' net interchange with non-participants. The Florida Reserve Sharing Group monitors participants' individual ACE, but calculates an RSG ACE based on the aggregate frequency biases and net interchange with non-participants.

Yes

No

This standard has been and should continue to be results based. R2 imposes a tracking and evidentiary requirement which is unreasonable and is not warranted by past performance and results. If the logical next step to be standards proscribing the measurement, qualification, etc. for contingency reserves?

No

Agree with the the VRF for R1, but not R2 for the reasons described in response to Question 6.
No
Same response as Question 6.
No
Yes
Provide flexibility for an RSG ACE to be calculated based on aggregate participants frequency bias and RSG interchange with non-participants.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtsen
LG&E and KU Services
No
The PPL NERC Registered Affiliates suggest striking the language "due to forced outage of transmission equipment." A responsible entity can cut a tag for reasons other than a forced outage of transmission equipment (equipment OLs, contingency/stability/voltage criteria, etc.) – the sink BA experiencing the loss of the import may not know the reason and thus not know if the loss meets the definition of a Balancing Contingency Event. The SDT replied to this comment during the Formal Comment Period, but missed the point. The curtailment would be communicated, however, the reason, "due to ..." would not necessarily.
No
The PPL NERC Registered Affiliates believe the proposed modifications actually introduce ambiguity and error. Attempting to provide examples (such as...) in definitions is ill-advised as this adds ambiguity to the definition as the list may be considered all inclusive by some and not by others. The final sentence should be struck. As defined by NERC, Demand Side Management includes "all activities" used to "influence" energy usage, which includes programs such as time of day rates, light bulb replacement, and other efficiency programs which do not provide controllable capacity. It appears the SDT may have intended to include the NERC defined term Direct Control Load Management as an example, however, examples need not be included in definitions.
No
The PPL NERC Registered Affiliates believe the definition should include only those BAs participating in the specific event, not simply all BAs that are members of the RSG. Suggest revising the definition as follows: -- Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (as calculated at such time of measurement) of all of the Balancing Authorities that are participating in the Balancing Contingency Event. --
No
The PPL NERC Registered Affiliates do not agree with the proposed modifications to the NERC defined term Contingency Reserve as explained in our comment 2.
No
PPL NERC Registered Affiliates do not agree that the development of additional requirements is necessary to meet the FERC directive for a continent wide policy. Additional comments on this topic provided under question 10.
No



positive, or something like that; but, reading the requirement literally, I believe it would be difficult to prove compliance using integrated values for ACE that will likely not equal zero.

Group

MISO Standards Collaborators

Marie Knox

MISO

No

No

The presently approved NERC definition for contingency seems adequate for this standard.

No

This change was not proposed in the drafting team's SAR and we see no FERC directive to make this change. RSGs have measurement processes that have worked well for quite some time. If the drafting team has guidance on the measurement process, that should be put in a supporting document rather than hard-coding additional obligations in the standard.

No

It needs a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.

No

R2 has nothing to do with a Continent Wide Contingency Reserve Policy and there is nothing in the drafting team's SAR that calls for the implementation of a commodity standard. This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies they carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The last most significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR nor in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. A fundamental flaw in R2 is that drafting team has implemented a commodity expectation that the BA must have contingency reserves above MSSC at all times and yet has provided no clear definition on how this is measured (does it include all generation headroom available in 10 minutes? In 15 minutes? What about resources that are also providing AGC? Does their instantaneous headroom count? Are load resources available in 15 minutes or 10 minutes counted? What type of proof of deliverability is required? Some of the background information implies that frequency responsive resources must be removed from the Contingency Reserve calculation. How much? All headroom? Enough to provide the IFRO? This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the ultimate demonstration of adequacy. We believe the way a way to achieve the Commissions directive for a continent wide "contingency reserve" policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The document the drafting team is working on is a good start. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through

the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.

No

We believe the requirement itself is inappropriate, so any VRF is unnecessary.

Yes

No

Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.

No

There first needs to be agreement on the requirements before there is concurrence with the background document.

Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL are crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives. The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. A Contingency Reserve Policy Guideline document in conjunction with the recommendations below should be sufficient to meet the drafting team SARs and the directives:

- Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes).
- Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency.
- Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. Also BAL-001's RBC is a more effective way to meet the FERC directive for loss of load events.
- The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA's performance approaches non-compliance.
- The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority.

Group

Tampa Electric Company

Ronald L Donahey

Tampa Electric Company

Agree

Duke Energy

Individual

Christopher Wood

Platte River Power Authority
Agree
Public Service Company of Colorado (Xcel Energy)
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela R. Hunter
Southern Company Operations Compliance
Yes
Yes
No
The definition should include only the BAs asked to participate in the reserve recovery event.
Yes
No
The proposed requirement would have significant negative consequences as Reserves are an inventory intended to be used when there is a reliability need. A BA could be encouraged to never deploy their CRs except for during a DCS-reportable event. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the time would start ticking on the 'available hours' clock. Additionally, BAs that don't withhold CRs for non-DCS events might feel the need to increase the amount of contingencies they carry in order to always have more reserves than their MSSC which in turn, would increase customer costs without a demonstrated need. We suggest that not all BAs have the same needs for the various types of operating reserves and that performance is the demonstration of adequacy. We suggest the SDT work with the NERC OC to create a policy document that outlines the factors the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves and provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standard's process, we suggest that NERC add these four types of reserves to 'Attachment 1-TOP-005 Electric System Reliability data" with the noted expectation that RCs collect this information in real time for use in the EEA process. While we agree with the principle of a BA maintaining Contingency Reserves to respond to its MSSC, the proposed R2 puts the BA at risk if CR reserves fall below its MSSC for any single sampling period. For example, BAs with a 2 second sampling interval would be at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the proposed Measures and VSLs, we suggest that specific language be included in R2 and not just in the Measure (SERC OC). A reference to the integrated clock hour should be included in R2 as in the Measure.
Yes
It is difficult to agree with the VRFs while disagreeing with the standard as proposed.
Yes
Yes
Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
No
The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." We disagree with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but

instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. We believe that the Commission clearly did not intend that any event that causes a frequency deviation, no matter how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500 MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample. We question whether this is appropriate and believes that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method. We suggest that additional details be provided in the background document relating to the methodology for development of the reporting thresholds.

There is an embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. We appreciate the SDT's goal of drafting a continent-wide standard but disagree with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, we believe that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500 MW as an example, a loss of 500 MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500 MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. We believe that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection. We respectfully suggest that the SDT give due consideration to redefining a Balancing Contingency Event and Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. We believe this is one approach that could satisfy the directive set forth in Order 693. In R1 and R2, delete the language related to an RE under an Energy Emergency Alert Level 2 or Level 3, for 2 reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. E.g. an EEA in effect for a BA in Florida should not be a consideration for the performance of a contingent RE anywhere in the EI. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE – this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Words could be added to R1 and R2 to clarify that the contingent RE is also the RE experiencing an EEA but a better solution is to simply delete the EEA related language from R1 and R2, Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection – wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. We suggest that a successful response by the RE would return ACE to the lesser of 0 or its real time BAAL low limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero)



and similarly – ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL low limit (if its Pre-Reportable Contingency Event ACE was negative). If the interconnection frequency is high – why require a BA to increase generation more than is necessary to meet its BAAL low limit? If interconnection frequency is low, the BAAL low limit as well as the zero or pre-contingent ACE rule would still apply.

Individual

Spencer Tacke

Modesto Irrigation District

No

It is in conflict with the very definition of a balancing authority.

Yes

No

A technical justification for the "16 second interval" for ACE and the "105 minutes" value for Contingency Reserve demonstration needs to be added.

Individual

Thomas Washburn

FMPP

Agree

FMPA

Group

ERCOT

H. Steven Myers

ERCOT ISO

Yes

Yes

ERCOT ISO suggests that the SDT consider the following changes so that the definition of the Contingency Reserve clearly accommodates resources eligible under the respective BA rules to provide Contingency Reserve for that BA: "The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by 'resources eligible under the respective BA rules, including, but not limited to,' resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation."

Yes

Yes

Yes

Yes
Yes
Yes
ERCOT ISO supports the intention of the standard BAL-002-2 R1 to restore ACE back to pre-disturbance ACE but not necessarily to zero or the pre-disturbance ACE. The ACE recovery goal should be pre-disturbance levels. Therefore, ERCOT suggests the SDT establish a ( $\epsilon_1 * \text{Frequency Bias} * 10$ ) band around the pre-disturbance ACE or zero ACE, and, if during recovery ACE is recovered within this range, entities would be compliant. This structure of establishing a goal, but providing for a compliance "floor" based upon the proposed range, will achieve the desired reliability benefits while also providing a reasonable degree of flexibility for circumstances where recovery to the exact pre-disturbance level is difficult to achieve, and unnecessary to ensure reliability. ERCOT ISO also suggests that the 500 MW threshold be removed from the definition of Reportable Balancing Contingency Event. This requirement would impose an undue burden. There is no reliability reason to require mandatory reporting for these smaller events. It will merely create an administrative obligation with no corresponding reliability benefits. For instance, currently ERCOT ISO would typically need to report less than five events annually, but this new standard would increase this reporting burden to over 50 each year (based upon 2012 disturbances), without any corresponding reliability benefits. Accordingly, this obligation should be removed. If the SDT elects not to remove the 500 MW threshold generally, ERCOT ISO suggests that the threshold be removed for single-BA Interconnections. The threshold for single-BA Interconnections should be established as 80 percent of the MSSC. ERCOT ISO is voting "yes", but has reservations as described above and requests that the SDT revise the standard accordingly.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
The definition is not explicitly clear about normal operating actions such as special protection system (SPS) actions. Certain transmission events may lead to generation rejection so the system stays stable after the fault. If we interpret the proposed definition and use the same terminology, these actions are planned, the change on the ACE is not unexpected, and they could be considered as a secondary event. The generation does not become unavailable following the trip. Consequently, these events would not classify as Balancing Contingency Events. During the 04/02/2013 webinar, the Standard Drafting Team provided an answer in this direction. We then understand that a CR Form 1 should not be filled for these types of events. However, we believe that the Balancing Contingency Event definition should be clarified to minimize the risk of misinterpretation if this is the SDT's intent. We suggest adding a bullet in the definition stating that normal operating characteristics of a unit or a system such as SPS actions do not constitute a sudden or unanticipated loss and are not subject to this definition. Additionally, some single contingencies may lead to generation loss as well as load loss after the breaker operations. For example, if 1200 MW of generation is lost and 1000 MW of DC converters at the same time, the net loss for the grid is 200 MW, which would be under the Reportable Balancing Contingency Event threshold. For this reason, the Balancing Contingency Event definition should include the notion of net loss for the grid.
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Group
ACES Standards Collaborators
Jason Marshall
ACES
No
(1) We appreciate the changes that have been made to the Balancing Contingency Event definition. It is much less complicated and more clear as a result. However, there still has not been a justification provided for the need of the definition. There is a statement in the background document that the previous version of the standard was "broad and could be interpreted in various manners". A specific explanation how the definition addresses the ambiguity should be provided. (2) We disagree with including subsection (c) in the Balancing Contingency Event definition. Subsection (c) includes sudden "loss of a known load used as a resource". Loss of a load will result in positive ACE regardless of whether it is being used a resource or not. As a result, BAL-002-2 R1 will be duplicative with BAL-013-1 R1. Both will compel recovery of ACE from the loss of a load. Think of it this way. If a 1000 MW load is used as a resource to respond to a BA's ACE that is at -100 MW, there would be 900 MW of load remaining once the load is reduced. If that load is then lost, ACE goes to 900 MW. Shouldn't this be covered by the proposed BAL-013-1?
No
Please strike the last sentence of the definition. It is an explanation of what may constitute contingency reserve and is not actually part of the definition. It should be included in the background document. We understand the reason for the inclusion may be in response to a directive to further the Commission's policy on expanding the use of DSM. However, the use of DSM has expanded significantly since the directives were issued and could be said to have been "overcome" by events. It is well understood within this industry that DSM may be used as a resource. The drafting team could include an explanation in the application guidelines or the background document that would explain that DSM could be used among other resources.
No
We believe the definition as proposed is already a common understanding and is not needed. We simply do not see how it adds value. Further, having multiple definitions for ACE creates confusion and is simply not needed.
No
(1) We do believe that it is helpful to clarify that a BA does not have to comply with recovering ACE and contingency reserves when it is in an EEA 2 or 3. It certainly would not make sense to go to the extreme of shedding firm load to recover ACE or contingency reserves if a BA was simply out of balance with no transmission security issues, system frequency issues or stability issues. There are standards requirements such as operating within IROs/SOLs that would deal with these other reliability issues and provide the indication if load needed to be shed to address the deficient BA. A more efficient way to address this issue may be to apply the restriction in the applicability section. (2) It would be helpful if the drafting team explained what the conflicts with the EOP standards are. Besides the one identified above, are there others? The background document states that there are conflicts but does not explain them. It is difficult to judge if the issue was addressed without an adequate explanation.
No

(1) We are concerned that this requirement will have unintended consequences. As written, a BA will be forced to only deploy contingency reserve for responding to resource contingencies. Consequently, the BA will have to carry more operating reserves which increases their operating costs tremendously without commensurate reliability benefit. Furthermore, there is no data indicating that operating reserves carried by BAs today are insufficient. (2) While contingency reserve is just one type of operating reserve and is intended for use to respond to contingent events, a BA should not be restricted to deploying it only for contingent events. There may be other reasons for a BA to have a large negative ACE (i.e. units don't ramp as expected) and the BA should be free to call upon its contingency reserve to recover ACE in such a situation. Since the FERC directive that is driving this requirement is to establish a continent wide policy on contingency reserve, a better solution would be for NERC to write an operating policy describing appropriate uses of various types of contingency reserves. A guideline document would provide better details for an operating policy than a requirement.

No

We agree with the VRF for requirement R1 but do not agree with requirement R2 as written. Thus, we do not agree with the VRF for Requirement R2.

Yes

No

We disagree with the VSLs for both requirements. The VSLs for requirement R1 raise the bar significantly for compliance without a technical justification. Today, DCS compliance is determined by a quarterly average of response to events. Thus, failure to recover ACE for two events within the same quarter would be a singular violation. As proposed, the new VSLs would treat each event as a separate violation. Without significant justification, we cannot agree with this change to the VSLs. Because we do not agree with Requirement R2, we do not agree with the corresponding VSLs.

No

(1) The background document needs to explain the conflict between BAL-002 and EOP-002 in detail rather than just stating that a conflict exists. (2) There is a statement on page 5 just before the Rationale by Requirement section that there are other definitions that have been added or modified. An explanation of what these are would be helpful. (3) The formulas starting on page 8 are overly complicated in an attempt to address the few situations where there are additional generator contingencies that occur shortly before or during the ACE recovery window. We suggest starting with simple formulas that consider that predominant situation where only one generator contingency occurs. Then build the more complicated formulas on that. It will be easier to explain. We also suggest using pictures to explain the formulas. For example, a graph showing the loss of a unit before and after the current contingency would help explain the formulas. The graph should include labels such as what ACE\_BEST, ACE\_PRE, and MEAS\_CR\_RESP are.

(1) We cannot support a 500 MW threshold for a Reportable Balancing Contingency Event. The number is arbitrary without any technical justification. The background document explains how the drafting team reviewed CERTS data to arrive at the conclusion that a 100 MW threshold would cover all frequency events. Correctly, the drafting team determined that this was simply an unrealistic threshold and would not provide any additional reliability value. The background document then explains that the drafting team decided "to capture the majority of events having significant impact on frequency" by setting the threshold to 80% of the MSSC or 500 MW. It did not explain which value would do this or why it was important "to capture the majority of events". Furthermore, there is no explanation why 500 MW is necessary when today 80% of MSSC is used. Has the use of 80% of MSSC resulted in an unreliable system? Thus, we can only conclude the value is arbitrary. Please remove the 500 MW value. (2) Additional justification is necessary to change the pre-disturbance calculation from an average of 10 to 60 seconds of ACE data prior to the disturbance to a 16-second interval. There is no explanation of this in the background document and we cannot support such a change without a justification for how it supports reliability. Furthermore, it is not consistent with BAL-005-0.2b which requires ACE calculation on at least a six second basis. A BA using a six-second sample rate could be viewed as being out of compliance if they used either two (12 seconds) or three (18 seconds) samples since they cannot use exactly 16 seconds of data. Furthermore, using only two or three samples could lead to unrealistic averages particularly if there are any glitches in the data. What does an entity do if a scan was skipped or there was a data spike? More samples would make it

less likely for this to be an issue. (3) The purpose needs to be modified. Please strike “balances resources and demand and”. The purpose of the standard is to recover ACE following a Reportable Balancing Contingency Event. The portion that needs to be struck is addressed by BAL-001. (4) The drafting team has an opportunity to assist NERC in moving the Reliability Assurance Initiative along and showing some of the first fruits of the initiative. One of the key white papers written for the initiative focuses on the reducing the data requirements and retention periods necessary for the compliance and enforcement process. NERC compliance has a stated goal of reducing the data retention burden on registered entities. The data retention required for the current versions of this standard exceed what is necessary and this draft version perpetuates the problem. All BAs currently must submit monthly data to their regional entities for this standard which clearly shows whether they are compliant or not. Then they are still required to retain three years worth of data. Since the regional entities already have the data and know whether they are compliant or not, what reliability value does three years of data provide? None. The new version will only perpetuate this issue. In response to our previous comments, the drafting team indicated that the monthly reporting is not required by the standard and is up to the region. While this is true, it is highly unlikely that the regional entities will change this monthly reporting burden given that the standard is conceptually the same as the existing standard. Furthermore, the drafting team and NERC staff can review the issue with regional entity compliance personnel to confirm their plans for monthly reporting. If they do plan to continue with the monthly reporting, then no more than six months of data is necessary and we request that the standard should be changed. It will demonstrate a good faith effort on the part of NERC to move the RAI forward. (5) The data retention section is inconsistent with the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C – Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since a BA is on a three-year audit cycle, the period from the previous audit will be about 3 years. It could be a little more or a little less. However, the data retention section of “the current year, plus three previous calendar years” (which could be up to four years) actually could exceed this three year audit cycle period. Consider if a BA completed their last audit on November 15, 2010. Their audit cycle would require another audit in 2013. Let’s assume this is scheduled for December 15, 2013. This means the audit period is 3 years and 1 month. It also means per the Rules of Procedure that NERC cannot review any period prior to November 15, 2010 for compliance unless there is an outstanding investigation. Per the data retention section, on December 15, 2013, the date of the audit, the BA would have to retain data for all of 2013 as well as all of the data for 2010, 2011 and 2012. By the Rules of Procedure, the auditors could not review any data prior to November 15, 2010. Thus, the registered entity would be compelled to retain for 11.5 months for which NERC is not allowed to review. How does this benefit reliability? The data retention period should be changed to retain data since the last audit. Changing the data retention period to be no longer than since the last audit would show a good faith effort in moving the RAI along. (6) The VSLs for Requirement R2 need to be justified. There is no explanation provided for the values chosen for the various thresholds. For example, the Lower VSL covers contingency deficiency for a period of 5 to 15 hours. Why shouldn’t this go to 20, 30, 40 or any other number of hours? Without a justification, we can only assume the numbers were selected arbitrarily. We are also confused by the Lower VSL since it starts at 5 hours. Does this mean that a BA can be deficient of contingency reserves up to 5 hours without a violation occurring? (7) There is no explanation for why Reportable Disturbance is not a satisfactory definition as used in the existing standard and why it is replaced with Reportable Balancing Contingency Event. Furthermore, it is not proposed to be retired. If the term will no longer be used, it should be retired. (8) Thank you for the opportunity to comment.

Individual

John Bee on Behalf of Exelon and its Affiliates

Exelon


While we appreciate the work done since previous versions of the project, and recognize the clarity gained by eliminating reference to Balancing Contingency Events with a future impact to ACE, we feel that additional confusion has been inserted by the sub-points of R1. Given that the recovery requirement is a relatively short time-frame, the ability to quickly determine the recovery obligation is critical to the ability to ensure compliance. We appreciate that the drafting team is attempting to accommodate the notion that a prior Balancing Contingency Event might impact any future events, but the methodology given for determining the recovery threshold is overly complex, and represents a significant barrier to a system operator's ability to interpret the requirement in Real Time and respond appropriately.

Individual

William O. Thompson

NIPSCO

Agree

MISO

Group

Tennessee Valley Authority

Dennis Chastain

Tennessee Valley Authority

Agree

SERC OC Standards Review Group

Individual

David Gordon

Massachusetts Municipal Wholesale Electric Company

Agree

Northeast Power Coordinating Council, Inc (NPCC) ISO New England, Inc.

Group

Oklahoma Gas & Electric

Terri Pyle

Oklahoma Gas & Electric

No

The definition of Reportable Balancing Contingency Event includes "the lesser of 80 percent of the MSSC or 500 MW". We believe that the threshold of 500 MW is too low. This is going to result in an excessive number of "reportable" events that do not have an impact on reliability. The retrieval and analysis of data will be burdensome and provide little value.

Yes

Yes

Yes

Yes

Yes

Yes

Yes
Yes
Remove the 500 MW threshold in the definition of Reportable Balancing Contingency Event
Group
IRC-SRC
Terry Bilke
MISO
No
We don't see the need for the added definition.
No
The presently approved NERC definition for contingency reserve seems adequate for this standard.
No
This change was not proposed in the drafting team's SAR and we see no FERC directive to make this change. RSGs have measurement processes that have worked well for quite some time. If the drafting team has guidance on the measurement process, that should be put in a supporting document rather than hard-coding additional obligations in the standard.
No
All that's needed is a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
No
We believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies they carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The last significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe the way a way to achieve the Commission's directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.
No
We believe the requirement itself is inappropriate, so any VRF is unnecessary.

Yes
No
Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
No
There first needs to be agreement on the requirements before there is concurrence with the background document.
Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL is crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives. The SAR for the drafting team was basically to clean up the VO clutter in the standard and address Order No 693 directives. The only two true requirements in the VO standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. Our recommendation are: • Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes). • Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. • Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. • The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA's performance approaches non-compliance. • The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority.
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Program
No
BPA recommends further clarity and explanation for the sudden unplanned outage of a transmission facility, and sudden loss of known load used as a resource that causes an unexpected change to responsible entity's ACE. BPA also recommends leaving in the failure to start language that has been removed.
Yes
Yes
Yes



Yes
Yes
Yes
No
BPA recommends changing the VSLs for R2 to: Lower VSL more than 2 but less than or equal to 5 hours; Moderate VSL more than 5 but less than or equal to 10 hours; High VSL more than 10 but less than or equal to 15 hours; Severe VSL More than 15 hours.
Yes
BPA is in support of this standard.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
If the DCS definition will not be used any longer, recommend the team retire it from the NERC glossary.
Yes
The drafting team is proposing to continue to use only ACE under Requirement R1 as the measure of reliability in the determination of Balancing Authority or RSG compliance. As has been seen in actual operation, the current methodology can lead to and has caused RC directives to drop load when there was not a reliability issue, defined as a frequency concern or transmission line loading issue. ACE is not a primary measure of reliability, only equity. Therefore, Xcel Energy is voting against the proposed standard. To remedy this deficiency in the proposed standard, the drafting team should utilize the BAAL limit as a more appropriate measure of response to the sudden loss of generation, not pre-event ACE or zero, whichever is lower. As proposed by Xcel Energy, this does not do away with DCS as originally proposed under BAAL but would change the measure of compliance in the DCS process to a more appropriate, reliability based measure. Xcel Energy is also not proposing to change the 15-minute period in BAL-002 for a reportable event with this modification.