Name (59 Responses)
Organization (59 Responses)
Group Name (28 Responses)
Lead Contact (28 Responses)
Question 1 (76 Responses)
Question 1 Comments (87 Responses)
Question 2 (77 Responses)
Question 2 Comments (87 Responses)
Question 3 (62 Responses)
Question 3 Comments (87 Responses)
Question 4 (0 Responses)
Question 4 Comments (87 Responses)

Individual
Brian Evans-Mongeon
Utility Services
Yes
While agreeing with the change, confusion may exist with the CAN that exists for the term "Annual". Utility Services suggests that the language be changed to "Every calendar year" or something equivalent. Given everything that transpired in the discussion on the term annual, using a different phrase may be advantageous.
Yes
Yes
There are no other comments at this time.
Individual
E Hahn
MWDSC
No
Tranmsission Owners (TO) should not be included as a "Responsible Entity" for this or other requirements because the Operating Plan is usually prepared by the Transmission Operator (TOP). For TOs who are not also TOPs, there are usually delegation agreements. CIP-001 never directly applied to TOs.
No
See comment for question 1
Individual
Scott McGough
Georgia System Operations Corporation
Yes
No
See comments under no. 4 below.
Yes
a) Reporting most of these items ... • Does not "provide for reliable operation of the BES" • Does not include "requirements for the operation of existing BES facilities" • Is not necessary to "provide for reliable operation of the BES" ... and is therefore not in accordance with the statutory and regulatory definitions of a Reliability Standard. They should not be in a Reliability Standard. Most of this is an

administrative activity to provide information for NERC to perform some mandated analysis. b) A reportable Cyber Security Incident: Delete this item from the table. It is covered in another standard and does not need to be duplicated in another standard. c) Damage or destruction of a Facility: Entities MAY only need to slightly modify their existing CIP-001 Sabotage Reporting procedures from a compliance perspective of HAVING an Operating Plan but not from a perspective of complying with the Plan. A change from an entity reporting "sabotage" on "its" facilities (especially when the common understanding of CIP-001 is to report sabotage on facilities as "one might consider facilities in everyday discussions") to reporting "damage on its Facilities" (as defined in the Glossary) is a significant change. An operator does not know off the top of his head the definition of Facility or Element. He will not know for any particular electrical device whether or not reporting is required. Although the term is useful for legal and regulatory needs, it is problematic for practical operational needs. This creates the need for a big change in guidance, training, and tools for an operator to know which pieces of equipment this applies to. There is the need to translate from NERC-ese to Operator-ese. Much more time is needed to implement. The third threshold ("Results from actual or suspected intentional human action") perpetuates the problem of knowing the human's intention. Also, what if the action was intended but the result was not intended? The third threshold is ambiguous and subject to interpretation. The original intent of this project was to get away from the problem of the term sabotage due to its ambiguity and subjectivity. This latest change reverses all of the work so far toward that original goal. Instead of the drafted language, change this item to reporting "Damage or destruction of a Facility and any involved human action" and use only the first two threshold criteria. d) Any physical threat that could impact the operability of a Facility: See comment above about the term "Facility" and the need for a much longer implementation time. e) Transmission loss: This item is very unclear. What is meant by "loss?" Above, it says to report damage or destruction of a Facility. This says to report the loss of 3 Facilities. Is the intent here to report when there are 3 or more Facilities that are unintentionally and concurrently out of service for longer than a certain threshold of time? The intent should not be to include equipment failure? Three is very arbitrary. An entity with a very large footprint with a very large number of electrical devices is highly likely to have 3 out of service at one time. An entity with very few electrical devices is less likely to have 3. Delete the word Transmission. It is somewhat redundant. A Facility is BES Element. I believe all BES Elements are Transmission Facilities. A Facility operates as a single "electrical device." What if more than 3 downstream electrical devices are all concurrently out of service due to the failure of one upstream device? Would that meet the criteria? A situation meeting the criteria will be difficult to detect. Need better operator tools, specific procedures for this, training, and more implementation time. f) The implementation plan says current version stays in effect until accepted by ALL regulatory authorities but it also says that the new version takes effect 12 months after the BOT or the APPLICABLE authorities accept it. It is possible that ONE regulatory authority will not accept it for 13 months and both versions will be in effect. It is also possible for ALL regulatory authorities to accept it at the same time, the current version to no longer be in effect, but the new version will not be in effect for 12 months.
Group
Northeast Power Coordinating Council
Guy Zito
No
Regarding Requirement R3, add the following wording from Measure M3 to the end of R3 after the wording “in Part 1.2.”: The annual test requirement is considered to be met if the responsible entity implements the communications process in Part 1.2 for an actual event. This language must be in the Requirement to be considered during an audit. Measures are not auditable. Regarding Requirement R4, replace the words “an annual review” with the words “a periodic review.” Add the following to R4: The frequency of such periodic reviews shall be specified in the Operating Plan and the time between periodic reviews shall not exceed five (5) years. This does not preclude an annual review in an Entity’s operating plan. The Entity will then be audited to its plan. If the industry approves a five (5) year periodic review ‘cap’, and FERC disagrees, then FERC will have to issue a directive, state it reasons and provide justification for an annual review that is not arbitrary or capricious. Adding the one year “test” requirement adds to the administrative tracking burden and adds no reliability value.
No
Regarding Attachment 1, language identical to event descriptions in the NERC Event Analysis Process and FERC OE-417 should be used. Creating a third set of event descriptions is not helpful to system

operators. Recommend aligning the Attachment 1 wording with that contained in Attachment 2, DOE Form OE-417 and the EAP whenever possible. The following pertains to Attachment 1: Replace the Attachment 1 “NOTE” with the following clarifying wording: NOTE: The Electric Reliability Organization and the Responsible Entity’s Reliability Coordinator will accept the DOE OE-417 form in lieu of Attachment 2 if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, Voice: 609-452-1422. Initial submittal by Voice within the reporting time frame is acceptable for all events when followed by a hardcopy submittal by Facsimile or e-mail as and if required. The proposed “events” are subjective and will lead to confusion and questions as to what has to be reported. Event: A reportable Cyber Security Incident. All reportable Cyber Security Incidents may not require “One Hour Reporting.” A “one-size fits all” approach may not be appropriate for the reporting of all Cyber Security Incidents. The NERC “Security Guideline for the Electricity Sector: Threat and Incident Reporting” document provides time-frames for Cyber Security Incident Reporting. For example, a Cyber Security Compromise is recommended to be reported within one hour of detection, however, Information Theft or Loss is recommended to be reported within 48 hours. Recommend listing the Event as “A confirmed reportable Cyber Security Incident. The existing NERC “Security Guideline for the Electricity Sector: Threat and Incident Reporting” document uses reporting time-frames based on “detection” and “discovery.” Recommend using the word confirmed because of the investigation time that may be required from the point of initial “detection” or “discovery” to the point of confirmation, when the compliance “time-clock” would start for the reporting requirement in EOP-004-2. Event: Damage or destruction of a Facility Threshold for Reporting: revise language on third item to read: Results from actual or suspected intentional human action, excluding unintentional human errors. Event: Any physical threat that could impact the operability of a Facility This Event category should be deleted. The word “could” is hypothetical and therefore unverifiable and un-auditable. The word “impact” is undefined. Please delete this reporting requirement, or provide a list of hypothetical “could impact” events, as well as a specific definition and method for determining a specific physical impact threshold for “could impact” events other than “any.” Event: BES Emergency requiring public appeal for load reduction. Replace wording in the Event column with language from #8 on the OE-417 Reporting Form to eliminate reporting confusion. Following this sentence add, “This shall exclude other public appeals, e.g., made for weather, air quality and power market-related conditions, which are not made in response to a specific BES event.” Event: Complete or partial loss of monitoring capability Event wording: Delete the words “or partial” to conform the wording to the NERC Event Analysis Process. Event: Transmission Loss Revise to BES Transmission Loss Event: Generation Loss Revise to BES Generation Loss
No
The proposed new section does not contain specifics of the proposed system nor the interfacing outside of the system to support the report collecting.
The proposed standard is not consistent with NERC’s new Risk Based Compliance Monitoring. a. The performance based action to “implement its event reporting Operating Plan” on defined events, as required in R2, could be considered a valid requirement. However, the concern is that this requirement could be superseded by the NERC Events Analysis Process and existing OE-417 Reporting. b. The requirements laid out in R1, R3 and R4 are specific controls to ensure that the proposed requirement to report (R2) is carried out. However, controls should not be part of a compliance requirement. The only requirement proposed in this standard that is not a control is R2. NERC does not need to duplicate the enforcement of reporting already imposed by the DOE. DOE-417 is a well established process that has regulatory obligations. NERC enforcement of reporting is redundant. NERC has the ability to request copies of these reports without making them part of the Reliability Rules. Form EOP-004, Attachment 2: Event Reporting Form: Delete from the Task column the words “or partial”. Delete from the Task column the words “physical threat that could impact the operability of a Facility”. VSL’s may have to be revised to reflect revised wording.
Individual
Don Jones
Texas Reliability Entity
Yes
No

(1) In the Events Table, consider whether the item for “Voltage deviation on Facility” should also be applicable to GOPs, because a loss of voltage control at a generator (e.g. failure of an automatic voltage regulator or power system stabilizer) could have a similar impact on the BES as other reportable items. Note: We made this comment last time, and the SDT’s posted response was non-responsive to this concern. (2) In the Events Table, under Transmission Loss, the SDT indicated that reporting is triggered only if three or more Transmission Facilities operated by a single TOP are lost. What if four Facilities are lost, with two Facilities operated by each of two TOPs? That is a larger event than three Facilities lost by one TOP, but there is no reporting requirement? Determining event status by facility ownership is not an appropriate measure. The reporting requirements should be based on the magnitude, duration, or impact of the event, and not on what entities own or operate the facilities. (3) In the Events Table, under Transmission Loss, the criteria “loss of three or more Transmission Facilities” is very indefinite and ambiguous. For example, how will bus outages be considered? Many entities consider a bus as a single “Facility,” but loss of a single bus may impact as many as six 345kV transmission lines and cause a major event. It is not clear if this type of event would be reportable under the listed event threshold? Is the single-end opening of a transmission line considered as a loss of a Facility under the reporting criteria? (4) Combinations of events should be reportable. For example, a single event resulting in the loss of two Transmission Facilities (line and transformer) and a 950 MW generator would not be reportable under this standard. But loss of two lines and a transformer, or a 1000 MW generator, would be reportable. It is important to capture all events that have significant impacts. (5) In the Events Table, under “Unplanned control center evacuation,” “Loss of all voice communication capability” and “Complete or partial loss of monitoring capability,” GOPs should be included. GOPs also operate control centers that are subject to these kinds of occurrences, with potentially major impacts to the BES. Note that large GOP control centers are classified as “High Impact” facilities in the CIP Version 5 standards, and a single facility can control more than 10,000 MW of generation. (6) The “BES Emergency resulting in automatic firm load shedding” event row within Attachment 1 should include the BA as a responsible entity for reporting. Note that EOP-003-1 requires the BA to shed load in emergency situations (R1, R5 as examples), and any such occurrence should be reported.
(1) The ERO and Regional Entities should not be included in the Applicability of this standard. The only justification given for including them was they are required to comply with CIP-008. CIP-008 contains its own reporting requirements, and no additional reliability benefit is provided by including ERO and Regional Entities in EOP-004. Furthermore, stated NERC policy is to avoid writing requirements that apply to the ERO and Regional Entities, and we do not believe there is any sufficient reason to deviate from that policy in this standard. (2) Under Compliance, in section 1.1, all the words in “Compliance Enforcement Authority” should be capitalized. (3) Under Evidence Retention, it is not sufficient to retain only the “date change page” from prior versions of the Plan. It is not unduly burdensome for the entity to retain all prior versions of its “event reporting Operating Plan” since the last audit, and it should be required to do so. (What purpose is supposed to be served by retaining only the “date change pages”?) (4) The title of part F, “Interpretations,” is incorrect on page 23. Should perhaps be “Associated Documents.”
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
Yes
None
Individual
Jonathan Appelbaum
United Illuminating Company
Yes

R3 should be clear that the annual test of the plan does not mean each communication path for each applicable event on an annual basis.
Yes
The phrasing of the event labeled as Event Damage or Destruction of a Facility may be improved in the Threshold for Reporting Column. Suggest the introduction sentence for this event should be phrased as Where the Damage or Destruction of a Facility: etc. The rationale for the change is that as written it is unclear if the list that follows is meant to modify the word Facilities or the overall introductory sentence. The confusion being caused by the word That. What is important to be reported is if a Facility is damaged and then an IROL is affected it should be reported, not that if a Facility is comprising an IROL Facility is damaged but there is no impact on the IROL. Second, the top of each table is the phrase Submit EOP-004 Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within one hour of recognition of the event. This creates the requirement that the actual form is required to be transmitted to parties other than NERC/DOE. The suggested revision is Submit EOP-004 Attachment 2 or DOE-OE-417 report to NERC and/or DOE, and complete notification to other organizations identified pursuant to Requirement R1 Part 1.2 within one hour etc..
The measures M3 and M4 require evidence to be dated and time stamped. The time stamp is excessive and provides no benefit. A dated document is sufficient. The measure M2 requires in addition to a record of the transmittal of the EOP-004 Attachment 2 form or DOE-417 form that an operator log or other operating documentation is provided. It is unclear why this supplemental evidence of operator logs is required. We are assuming that the additional operator logs or documentation is required to demonstrate that the communication was completed to organizations other than NERC and DOE of the event. If true then the measure should be clear on this topic. For communication to NERC and DOE use the EOP-004 Form or OE-417 form and retain the transmittal record. For communication to other organizations pursuant to R1 Part 1.2 evidence may include but not limited to, operator logs, transmittal record, attestations, or voice recordings.
Individual
Dan Roethemeyer
Dynegy Inc.
Yes
Yes
Use of the term "Part x.x" throughout the Standard is somewhat confusing. I can't recall other Standards using that type of term. Suggest using the term "Requirement" instead.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst votes in the Affirmative for this standard because the standard further enhances reliability by clearing up confusion and ambiguity of reporting events which were previously reported under the EOP-004-1 and CIP-001-1 standards. Even though ReliabilityFirst votes in the Affirmative, we offer the following comments for consideration: 1. Requirement R1, Part 1.2 a. ReliabilityFirst recommends further prescribing whom the Responsible Entity needs to communicate with. The phrase “… and other organizations needed for the event type…” in Part 1.2 essentially leaves it up to the Responsible Entity to determine (include in their process) whom they should communicate each applicable event to. ReliabilityFirst recommends added a fourth column under Attachment 1, which lists whom the Responsible Entity is required to communicate with, for each applicable event. 2. VSL for Requirement R2 a. Requirement R2 requires the Responsible Entity to “implement its event reporting Operating Plan” and does not require the entity to submit a report. For consistency with the requirement, ReliabilityFirst recommends modifying the VSLs to begin with the following type of

language: “The Responsible Entity implemented its event reporting Operating Plan more than 24 hours but...” This recommendation is based on the FERC Guideline 3, VSL assignment should be consistent with the corresponding requirement and should not expand on, nor detract from, what is required in the requirement.
Individual
Joe Petaski
Manitoba Hydro
No
(R1.1 and 1.2) It is unclear whether or not R1.1 and R1.2 require a separate recognition and communication process for each of the event types listed in Attachment 1 or if event types can be grouped as determined appropriate by the responsible entity given that identical processes will apply for multiple types of events. Manitoba Hydro suggests that wording is revised so that multiple event types can be addressed by a single process as deemed appropriate by the Responsible Entity. (R3) It is unclear whether or not R3 requires the testing of the communications process for each separate event type identified in Attachment 1. If so, this would be extremely onerous. Manitoba Hydro suggests that only unique communication processes (as identified by the Responsible Entity in R1.2) require an annual test and that testing should not be required for each type of event listed in Attachment 1. As well, Manitoba Hydro believes that testing the communications process alone is not as effective as also providing training to applicable personnel on the communications process. Manitoba Hydro suggests that R3 be revised to require annual training to applicable personnel on the communications process and that only 1 test per unique communications process be required annually.
Yes
Yes
Manitoba Hydro is voting negative on EOP-004-2 for the reasons identified in our response to Question 1. In addition, Manitoba Hydro has the following comments: (Background section) - The section has inconsistent references to EOP-004 (eg. EOP-004 and EOP-004-2 are used). Wording should be made consistent. (Background section) – The section references entities, and responsible entities. Suggest wording is made consistent and changed to Responsible Entities. (General comment) – References in the standard to ‘Part 1.2’ should be changed to R1.2 as it is unclear if Part 1.2 refers to, for example, R1.2 or part 1.2 ‘Evidence Retention’. (M4) –Please clarify what is meant by ‘date change page’.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP agrees that it is appropriate to test reporting communications on an annual basis, primarily to validate that phone numbers, email ids, and contact information is current. We appreciate the project team’s elimination of the terms “exercise” and “drill”, which we believe connotates a formalized planning and assessment process. An annual review of the Operating Plan implies a confirmation that linkages to sub-processes remain intact and that new learnings are captured. We also agree that it is appropriate only to require an updated Revision Level Control chart entry as evidence of compliance – it is very likely that no updates are required after the review is complete. In our view, both of these requirements are sufficient to assure an effective assessment of all facets of the Operating Plan. As such, we fully agree with the project team’s decision to delete the requirement to update the plan within 90 days of a change. In most cases, our internal processes will address the updates much sooner, but there is no compelling reason to include it as an enforceable requirement.
Yes
Ingleside Cogeneration LP agrees with the removal of nearly all one hour reporting requirements. In our view there must be a valid contribution expected of the recipients of any reporting that takes place this early in the process. Any non-essential communications will impede the progress of the

front-line personnel attempting to resolve the issue at hand – which has to be the priority. Secondly, there is a risk that early reporting may include some speculation of the cause, which may be found to be incorrect as more information becomes available. Recipients must temper their reactions to account for this uncertainty. In fact, Ingleside Cogeneration LP recommends that the single remaining one-hour reporting scenario be eliminated. It essentially defers the reporting of a cyber security incident to CIP-008 anyways, and may even lead to a multiple violation of both Standards if exceeded.
Yes
Ingleside Cogeneration is encouraged by NERC's willingness to act as central data gathering point for event information. However, we see this only as a starting point. There are still multiple internal and external reporting demands that are similar to those captured in EOP-004-2 – examples include the DOE, RAPA (misoperations), EAWG (events analysis), and ES-ISAC (cyber security). Although we appreciate the difference in reporting needs expressed by each of these organizations, there are very powerful reporting applications available which capture a basic set of data and publish them in multiple desirable formats. We ask that NERC spearhead this initiative – as it is a natural part of the ERO function.
Ingleside Cogeneration LP strongyly believes that LSEs that do not own BES assets should be excluded from the Applicability section of this standard.
Group
DECo
Kent Kujala
No
Should only have annual "review" requirement rather than test.
No
On pg 17 in the Rationale Box for EOP-004 Attachment 1: The set of terms is specific then includes the word ETC. Then further lists areas to exclude. Then on Pg 23 of document it includes train derailment near a transmission right of way and forced entry attempt into a substation facility as reportable. These conflict. Also see conflict when in pg 21 states the DOE OE417 would be excepted in lieu of the NERC form, but on the last pg it states the DOE OE417 should be attached to the NERC report indicating the NERC report is still required.
Yes
Requirement R3 for annual test specifically states that ERO is not included during test. Implies that local law enforcement or state law enforcement will be included in test. Hard to coordinate with many Local organizations in our area.
Individual
Tim Soles
Occidental Power Services, Inc.
No
There should be an exception for LSEs with no BES assets from having an Operating Plan and, therefore, from testing and review of such plan. These LSEs have no reporting responsibilities under Attachment 1 and, if they have nothing ever to report, why would they have to have an Operating Plan and have to test and review it? This places an undue burden on small entities that cannot impact the BES.
No
There are no requirements in Attachment 1 for LSEs without BES assets so these entities should not be in the Applicability section.
No
This section should reference the confidentiality requirements in the ROP and should have a statement about the system for collection and dissemination of disturbance reports being "subject to the confidentiality requirements of the NERC ROP."
OPSI continues to believe that LSEs that do not own BES assets should be excluded from the Applicability section of this standard. It is disingenuous of both the SDT and FERC to promote an

argument to support this inclusion such as that stated in Section 459 of Order 693 (and referred to by the SDT in their Consideration of Comments in the last posting). The fact is that no reportable disturbance can be caused by an “attack” on an LSE that does not own BES assets. The SDT has yet to point out such an event.
Individual
Alice Ireland
Xcel Energy
No
1) In R1.2, We understand what the drafting team had intended here. However, we are concerned that the way this requirement is drafted, using i.e., it could easily be interpreted to mean that you must notify all of those entities listed. Instead, we are suggesting that the requirement be rewritten to require entities to define in their Operating Plan the minimum organizations/entities that would need to be notified for applicable events. We believe this would remove any ambiguity and make it clear for both the registered entity and regional staff. We recommend the requirement read something like this: 1.2. A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to applicable internal and external organizations needed for the event type, as defined in the Responsible Entity’s Operating Plan. 2) We also suggest that R3 be clarified as to whether communications to all organizations must be tested or just those applicable to the test event type/scenario.
No
1) The event Damage or destruction of a Facility appears to need ‘qualifying’. Is this intended for only malicious intent? Otherwise, weather related or other operational events will often meet this criteria. For example adjustment in generation or changes in line limits to “avoid an Adverse Reliability Impact” could occur during a weather related outage. We suggest adjusting this event and criteria to clearly exclude certain items or identify what is included. 2) Also recommend placing the information in footnote 1 into the associated Threshold for Reporting column, and removing the footnote.
We believe such a tool would be useful, however we are indifferent as to if it is required to be established by the Rules of Procedure.
Xcel Energy appreciates the work of the drafting team and believes the current draft is an improvement over the existing standard. However, we would like to see the comments provided here and above addressed prior to submitting an AFFIRMATIVE vote. 1) Suggest enhancing the “Example of Reporting Process…” flowchart as follows: EVENT > Refer to Ops Plan for Event Reporting > Refer to Law Enforcement? > Yes/No > …. 2) Attachment 1 – in both the 1 hour and the 24 hour reporting they are qualified with “within x hours of recognition of the event”. Is this the intent, so that if an entity recognizes at some point after an event that the time clock starts? 3) VSLs – R3 & R4 “Severe” should remove the “OR….”, as this is redundant. Once an entity has exceeded the 3 calendar months, the Severe VSL is triggered. 4) The Guideline and Technical Basis page 22 should be corrected to read “The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.” 5) Also in the following section of the Guideline and Technical Basis (page 23) the third bullet item should be qualified to exclude copper theft: Examples of such events include: • Bolts removed from transmission line structures • Detection of cyber intrusion that meets criteria of CIP-008-3 or its successor standard • Forced intrusion attempt at a substation (excluding copper theft) • Train derailment near a transmission right-of-way • Destruction of Bulk Electric System equipment
Group
Duke Energy
Greg Rowland
No
Under R3, we agree with testing communications internally. Just as the ERO is excluded under R3, other external entities should also be excluded. External communications should be verified under R4.
No
(1)We disagree with reporting CIP-008 incidents under this standard. We agree with the one-hour notification timeframe, but believe it should be in CIP-008 to avoid double jeopardy. (2)Damage or

destruction of a Facility – Need clarity on how a vertically integrated entity must report. For example a GOP probably won't know if an IROL will be affected. Also, there shouldn't be multiple reports from different functional entities for the same event. Suggest splitting this table so that GO, GOP, DP only reports "Results from actual or suspected intentional human action". (3)Generation Loss – Need more clarity on the threshold for reporting. For example if we lose one 1000 MW generator at 6:00 am and another 1000 MW generator at 4:00 pm, is that a reportable event?
Yes
Group
Luminant
Brenda Hampton
Yes
No
Luminant appreciates the work of the DSR SDT to modify Attachment 1 to address the concerns of the stakeholders. However, we are concerned that the threshold for reporting a Generation Loss in the ERCOT interconnection established by this revision is set at ≥ 1,000MW, which is not consistent with the level of single generation contingency used in ERCOT planning and operating studies. That level of contingency is currently set at the size of the largest generating unit in ERCOT, which is 1,375MW. For this reason, Luminant believes that the minimum threshold for reporting of a disturbance should be > 1,375MW for the ERCOT Interconnection.
Yes
Group
BC Hydro
Patricia Robertson
Yes
No
BC Hydro supports the revisions to EOP-004 and would vote Affirmative with the following change. Attachment 1 has a One Hour Reporting requirement. BC Hydro proposes a One Hour Notification with the Report submitted within a specified timeframe afterward.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
Austin Energy (AE) supports the requirements for (1) an annual test of the communications portion of the Operating Plan (R3) and (2) an annual review of the Operating Plan (R4); however, we offer a slight modification to the measures associated with those requirements. AE does not believe that records evidencing such test and reviews need to be time-stamped to adequately demonstrate compliance with the requirements. In each case, we recommend that the first sentence of M3 and M4 start with "Each Responsible Entity will have dated records to show that the annual …"
Yes
Austin Energy makes the following comments: (1) Comment on the Background section titled "A Reporting Process Solution – EOP-004": This section includes the sentence, "Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state OR PROVINCIAL

OR LOCAL level law enforcement agency." (emphasis added) The corresponding flowchart includes a step, "Notification Protocol to State Agency Law Enforcement." Austin Energy requests that the SDT update the flowchart to match the language of the associated paragraph and include "state or provincial or local" agencies. (2) Comments on VSLs: Austin Energy recommends that the SDT amend the VSLs for R2 to include the "recognition of" events throughout. That is, update the R2 VSLs to state "… X hours after "recognizing" an event …" in all locations where the phrase occurs. (3) Austin Energy has a concern with the inclusion of the word "damage" to the phrase "damage or destruction of a Facility." We agree that any "destruction" of a facility that meets any of the three criteria be a reportable event. However, if the Standard is going to include "damage," some objective definition for "damage" (that sets a floor) ought to be included. Much like the copper theft issue, we do not see the benefit of reporting to NERC vandalism that does not rise to a certain threshold (e.g. someone who takes a pot shot at an insulator) unless the damage has some tangible impact on the reliability of the BES or is an act of an orchestrated sabotage (e.g. removal of a bolt in a transmission structure). (4) Austin Energy voted to approve the revised Standard because it is an improvement over the existing Standard. In light of FERC's comments in Paragraph 81 of the Order approving the Find, Fix, Track and Report initiative, however, Austin Energy would propose that this Standard is the type of Standard that does not truly enhance reliability of the BES and is, instead, an administrative activity. As such, we recommend that NERC consider whether EOP-004-2 ought to be retired.
Group
Bonneville Power Administration
Chris Higgins
Yes
BPA believes that the annual testing and review as described in R3 is too cumbersome and unnecessary for entities with large footprints to inundate federal and local enforcement bodies such as the FBI for "only" testing and the documenting for auditing purposes. BPA suggests that testing be performed on a bi-annual or longer basis.
No
BPA believes that clarifying language should be added to transmission loss event. (Page 19) [a report should not be required if the number of elements is forced because of pre-designed or planned configuration. System studies have to take such a configuration into account possible wording could be. Unintentional loss of three or more Transmission Facilities (excluding successful automatic reclosing or planned operating configuration)] In addition, under the "Event" of Complete or partial loss of monitoring capability, BPA believes that "partial loss" is not sufficiently specific for BPA to write compliance operating procedures and suggest defining partial loss or removing it from the standard. Should the drafting team add clarifying language to remove "or partial loss" and address BPA's concerns on over emphasis on software tool to the operation of the system. BPA would change its negative position to affirmative.
Yes
BPA believes that the VSL should allow for amending the form after a NERC specified time period without penalty and suggests that a window of 48 hours be given to amend the form to make adjustments without needing to file a self report. Should the standard be revised to allow a time period for amending the form without having to file a self report, BPA would change its negative position to affirmative.
Individual
Thad Ness
American Electric Power
No
R3: How many different scenarios need to be tested? For example, reporting sabotage-related events might well be different than reporting reliability-related events such as those regarding loss of Transmission. While these examples might vary a great deal, other such scenarios may be very similar in nature in terms of communication procedures. Perhaps solely testing the most complex procedure would be sufficient. AEP agrees with the changes with R3 calling for an annual test provided the requirement R2 is modified to include the measure language "The annual test requirement is considered to be met if the responsible entity implements the communications process

in Part 1.2 for an actual event." M3: While we agree that "the annual test requirement is considered to be met if the responsible entity implements the communications process in Part 1.2 for an actual event", we believe it would be preferable to include this text in R3 in addition to M3. Measures included in earlier standards (some of which are still enforced today) had little correlation to the requirement itself, and as a result, those measures were seldom referenced. M3: It would be unfair to assume that every piece of evidence required to prove compliance would be dated and time-stamped, so we recommend removing the text "dated and time-stamped" from the first sentence so that it reads "Each Responsible Entity will have records to show that the annual test of Part 1.2 was conducted." The language regarding dating and time stamps in regards to "voice recordings and operating logs or other communication" is sufficient.
No
If CIP-008 is now out of scope within the requirements of this standard, any references to it should also be removed from Attachment 1. The Threshold for Reporting column on page 26 includes "Results from actual or suspected intentional human action." This wording is too vague as many actions by their very nature are intentional. In addition, it should actually be used as a qualifying event rather than a threshold. We recommend removing it entirely from the Threshold column, and placing it in the Events column and also replacing the first row as follows: "Actual or suspected intentional human action with the goal of damage to, or destruction of, the Facility." On page 27, the event "Any physical threat that could impact the operability of a Facility" is too vague and broad. Using the phrases "any physical threat" and "could impact" sets too high a bar on what would need to be reported. On page 28, for the event "Complete loss of off-site power to a nuclear generating plant (grid supply)", TO and TOP should be removed and replaced by GOP.
Yes
While we have no objections at this point, we would like specific details on what our obligations would be as a result of these changes. For example, would the clearinghouse tool provide verifications that the report(s) had been received as well as forwarded? In addition, if DOE OE-417 is the form being submitted, would the NERC Reporting Clearinghouse forward that report to the DOE?
While we do not necessarily disagree with modifying this standard, we do have serious concerns with the possibility that Form OE-417 form would not also be modified to match any changes made to this standard. To the degree they would be different, this would create unnecessary confusion and burden on operators. If CIP-008 is now out of scope within the requirements of this standard, the task "reportable Cyber Security Incident" should be removed from Attachment 2.
Individual
Ed Davis
Entergy
No
The requirement for a "time stamped record" of annual review is unreasonable and unnecessary. A dated document showing that a review was performed should be sufficient.
Yes
Entergy does not agree with the Time Horizon for R2. The rationale for R2 contains phrases related to situational awareness and keeping people/agencies aware of the "current situation." However, this standard is related to after the fact event reporting, not real-time reporting via RCIS, as discussed on page 6 of the red-lined standard. Therefore the time horizon for R2 should indicate that this is an after the fact requirement expected to be performed either in 1 hour or 24 hours after an event occurs, not in the operations assessment time frame. This change should also be made on page 15 of the redline in the Table of compliance elements for R2. Page 18 of the redline document contains a VSL for R2 which states that it will be considered a violation if the Responsible Entity submitted a report in the appropriate timeframe but failed to provide all of the required information. It has long been the practice to submit an initial report and provide additional information as it becomes available. On page 24 of the redlined document, this is included in the following "...and provide as much information as is available at the time of the notification to the ERO..." But the compliance elements table now imposes that if the entity fails to provide ALL required information at the time the initial report is required, the entity will be non compliant with the standard. This imposes an

unreasonable burden to the Reliability Entity. This language should be removed. The compliance element table for R3 and R4 make it a high or severe violation to be late on either the annual test or the annual review of the Operating plan for communication. While Entergy supports that periodically verifying the information in the plan and having a test of the operating plan have value, it does not necessarily impose additional risk to the BES to have a plan that exceeds its testing or review period by two to three months. This is an administrative requirement and the failure to test or review should be a lower or moderate VSL, which would be consistent with the actual risk imposed by a late test or review. On page 24 of the redlined draft, there is a statement that says “In such cases, the affected Responsible Entity shall notify parties per Requirement R1 and provide as much information as if available at the time of the notification…” Since R1 is the requirement to have a plan, and R2 is the requirement to implement the plan for applicable events, it seems that the reference in this section should be to Requirement R2, not Requirement R1.
Individual
Jack Stamper
Clark Public Utilities
Yes
No
I agree with all but one. The event is "Damage or destruction of a Facility" and the threshhold for reportin is "Results from actual or suspected intentional human action." I understand and agree that destruction of a facility due to actual or suspected intentional human action should always be reported. However, I do not know what level of damage should be reported. Obviously the term "damage" is meant to signify and event that is less than destruction. As a result, damage could be extensive, minimal, or hardly noticeable. There needs to be some measure of what the damage entails if the standard is to contain a broad requirement for the reporting of damage intentionally caused by human action. Whether that measure is based on the actual impacts to the BES from the damage or whether the measure is based on the ability of the damaged equipment to continue to function at 100%, 50% or some capability would be acceptable but currently it is too open ended.
Yes
Individual
Tracy Richardson
Springfield Utility Board
Yes
• SUB supports the removal of Requirement 1, Part 1.4, as well the separation of Parts 1.3 and 1.5, agreeing that they are their own separate actions. • The Draft 4 Version History still lists the term “Impact Event” rather than “Event”.
Yes
• Spell out Requirement 1, rather than “parties per R1” in NOTE. • On page 44, “Examples of such events include” should say, “include, but are not limited to”. • SUB appreciates clarification regarding events, particularly the discussion regarding “sabotage”, and recommends listing and defining “Event” in Definitions and Terms Used in NERC Standards. • The Guideline and Technical Basis provides clarity, and SUB agrees with the removal of “NERC Guideline: Threat and Incident Reporting”. • In the flow chart on page 9 there are parallel paths going from “Refer to Ops Plan for Reporting” to the ‘Report Event to ERO, Reliability Coordinator’ via both the Yes and No response. It seems like the yes/no decision should follow after “Refer to Ops Plan” for communication to law enforcement.
Yes
• SUB supports the new Section 812 being incorporated into the NERC ROP. This addition provides clarity for what is required by whom and takes away any possible ambiguity.
SUB appreciates the opportunity to provide comments. While Staff was concerned with the consolidation of CIP and non-CIP NERC Reliability Standards (as to how they’ll be audited), the Project 2009-01 SDT has done an excellent job in providing clarification around identifying and reporting events, particularly related to the varying definitions of “sabotage”.

Individual
Wayne Sipperly
New York Power Authority
No
Please see comments submitted by NPCC Regional Standards Committee (RSC).
No
Please see comments submitted by NPCC Regional Standards Committee (RSC).
Yes
Please see comments submitted by NPCC Regional Standards Committee (RSC).
Individual
David Thorne
Pepco Holdings Inc
Yes
Yes
No
This could create confusion. This new ROP section states that "… the system shall then forward the report to the appropriate NERC departments, applicable regional entities, other designated registered entities, and to appropriate governmental, law enforcement, regulatory agencies as necessary." Standard Section R1.2 states "A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement, governmental or provincial agencies." If NERC is going to be the "clearinghouse" forwarding reports to the RE and DOE, does that mean that the reporting entity only needs to make a single submission to NERC for distribution? If the reporting entity is required to make all notifications, per R1.2, what is the purpose of NERC's duplication of sending out reports? It would be very helpful to the reporting entities if R1.2 was revised to state that NERC would forward the event form to the RE and DOE and the reporting entity would only be responsible for providing notice verbally to its associated BA, TOP, RC, etc. as appropriate and for notifying appropriate law enforcement as required.
The SDT's efforts have resulted in a very good draft.
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
Yes
Yes
Yes
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
Requirement R3: Following the sentence ending "in Part 1.2" add the following wording from the Measure to R3: The annual test requirement is considered to be met if the responsible entity implements the communications process in Part 1.2 for an actual event. This language must be in the Requirement to be considered during an audit. Measures are not auditable. Requirement R4: Replace

the words “an annual review” with the words “a periodic review.” Following the first sentence in R4 add: The frequency of such periodic reviews shall be specified in the Operating Plan and the time between periodic reviews shall not exceed five (5) years.
No
General comment regarding Attachment 1: SDT should strive to use identical language to event descriptions in the NERC Event Analysis Process and FERC OE-417. Creating a third set of event descriptions is not helpful to system operators. We recommend aligning the Attachment 1 wording with that contained in Attachment 2, DOE Form OE-417 and the EAP whenever possible. Replace the Attachment 1 “NOTE” with the following clarifying wording: NOTE: The Electric Reliability Organization and the Responsible Entity’s Reliability Coordinator will accept the DOE OE-417 form in lieu of Attachment 2 if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, Voice: 609-452-1422. Initial submittal by Voice within the reporting time frame is acceptable for all events when followed by a hardcopy submittal by Facsimile or e-mail as and if required. Event: Damage or destruction of a Facility Threshold for Reporting: revise language on third item to read, Results from actual or suspected intentional human action, excluding unintentional human errors. Event: Any physical threat that could impact the operability of a Facility This Event category should be deleted. The word “could” is hypothetical and therefore unverifiable and un-auditable. The word “impact” is undefined. Please delete this reporting requirement, or please provide a list of hypothetical “could impact” events, as well as a specific definition and method for determining a specific physical impact threshold for “could impact” events other than “any.” Event: BES Emergency requiring public appeal for load reduction. Replace Event wording with language from #8 on OE-417 reporting form to eliminate reporting confusion. Following this sentence add, “This shall exclude other public appeals, e.g., made for weather, air quality and power market-related conditions, which are not made in response to a specific BES event.” Event: Complete or partial loss of monitoring capability Event wording: Delete the words “or partial” to conform the wording to NERC Event Analysis Process. Event: Transmission Loss Modify to BES Transmission Loss Event Generation Loss Modify to BES Generation Loss
Yes
Form EOP-004, Attachment 2: Event Reporting Form: Delete the Task words “or partial.” Delete the Task words “physical threat that could impact the operability of a Facility.” Make any changes to the VSL’s necessary to align them with the reviewed wording provided above.
Individual
David Burke
Orange and Rockland Utilities, Inc.
No
Requirement R3: Following the sentence ending “in Part 1.2” add the following wording from the Measure to R3: The annual test requirement is considered to be met if the responsible entity implements the communications process in Part 1.2 for an actual event. This language must be in the Requirement to be considered during an audit. Measures are not auditable. Requirement R4: Replace the words “an annual review” with the words “a periodic review.” Following the first sentence in R4 add: The frequency of such periodic reviews shall be specified in the Operating Plan and the time between periodic reviews shall not exceed five (5) years.
No
General comment regarding Attachment 1: SDT should strive to use identical language to event descriptions in the NERC Event Analysis Process and FERC OE-417. Creating a third set of event descriptions is not helpful to system operators. We recommend aligning the Attachment 1 wording with that contained in Attachment 2, DOE Form OE-417 and the EAP whenever possible. Replace the Attachment 1 “NOTE” with the following clarifying wording: NOTE: The Electric Reliability Organization and the Responsible Entity’s Reliability Coordinator will accept the DOE OE-417 form in lieu of Attachment 2 if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, Voice: 609-452-1422. Initial submittal by Voice within the reporting time frame is acceptable for all events when followed by a hardcopy submittal by Facsimile or e-mail as and if required. Event: Damage or destruction of a Facility Threshold for Reporting: revise language on third item to read, Results from actual or suspected intentional human action, excluding unintentional human errors. Event: Any physical threat

that could impact the operability of a Facility This Event category should be deleted. The word "could" is hypothetical and therefore unverifiable and un-auditable. The word "impact" is undefined. Please delete this reporting requirement, or please provide a list of hypothetical "could impact" events, as well as a specific definition and method for determining a specific physical impact threshold for "could impact" events other than "any." Event: BES Emergency requiring public appeal for load reduction. Replace Event wording with language from #8 on OE-417 reporting form to eliminate reporting confusion. Following this sentence add, "This shall exclude other public appeals, e.g., made for weather, air quality and power market-related conditions, which are not made in response to a specific BES event." Event: Complete or partial loss of monitoring capability Event wording: Delete the words "or partial" to conform the wording to NERC Event Analysis Process. Event: Transmission Loss Modify to BES Transmission Loss Event Generation Loss Modify to BES Generation Loss
Yes
Form EOP-004, Attachment 2: Event Reporting Form: Delete the Task words "or partial." Delete the Task words "physical threat that could impact the operability of a Facility." Make any changes to the VSL's necessary to align them with the reviewed wording provided above.
Individual
Larry Raczkowski
FirstEnergy Corp
Yes
FE agrees with the revision but has the following comments and suggestions: 1. We request clarity and guidance on R3 (See our comments in Question 4 for further consideration). Also, we suggest a change in the phrase "shall conduct an annual test" to "shall conduct a test each calendar year, not to exceed 15 calendar months between tests". This wording is consistent with other standards in development such as CIP Version 5. 2.In R4 we suggest a change in the phrase "shall conduct an annual review" to "shall conduct a review each calendar year, not to exceed 15 calendar months between reviews". This wording is consistent with other standards in development such as CIP Version 5.
No
FE requests the following changes be made to Attachment 1: 1. Pg. 19 / Event: "Voltage deviation on a Facility". The term "observes" for Entity with Reporting Responsibility be changed to "experiences". The burden should rest with the initiating entity in consistency with other Reporting Responsibilities. 2. In "Threshold for Reporting", the language should be expanded to – plus or minus 10% "of nominal voltage" for greater than or equal to 15 continuous minutes. 3. Pg.20 /Event: "Complete or partial loss of monitoring capability". The term "partial" should be deleted from the event description to read as follows: Complete loss of monitoring capability and the reporting responsibility requirements to read "Each RC, BA, and TOP that experiences the complete loss of monitoring capability."
Yes
FE agrees but asks that the defined term "registered entities" in the second sentence be capitalized.
FE supports the standard and has the following additional comments and suggestions: 1. Guideline/Technical Basis Section – FE requests the SDT add specific guidance for each requirement. Much of the information in this section is either included, or should be included in the Background section of the standard. One example of guidance that would help is for Requirement R3 on how an entity could perform the annual test. The comment form for this posting has the following paragraph on pg. 2 which could be used as guidance for R3: "the annual test will include verification that communication information contained in the Operating Plan is correct. As an example, the annual update of the Operating Plan could include calling "others as defined in the Responsibility Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated. Note that there is no requirement to test the reporting of events to the Electric Reliability Organization and the Responsible Entity's Reliability Coordinator." 2. With regard to the statement in the comment form (pg 2 paragraph 7)"Note that there is no requirement to test the reporting of events to the Electric Reliability Organization and the Responsible Entity's Reliability Coordinator.", requirement R3 only includes the ERO as an entity and should also include the Reliability Coordinator. 3. The measure M3 says that an entity can use an actual event as a test to meet R3. Does this mean just 1 actual event will meet R3,

or is the intent that all possible events per 1.2 are tested? Would like some clarity on this measure.
Individual
Linda Jacobson-Quinn
Farmington Electric Utility System
Yes
No
The reporting threshold for “Complete or partial loss of monitoring capability” should be modified to include the loss of additional equipment and not be limited to State Estimator and Contingency Analysis. Some options have been included: Affecting a BES control center for ≥ 30 continuous minutes such that Real-Time monitoring tools are rendered inoperable. Affecting a BES control center for ≥ 30 continuous minutes to the extent a Constrained Facility would not be identified or an Adverse Reliability Impact event could occur due to lack of monitoring capability. Affecting a BES control center for ≥ 30 continuous minutes such that an Emergency would not be identified or ma
Yes
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We concur with the changes as they provide better streamlining of the four key requirements, with enhanced clarity. However, we are unclear on the intent of Requirement R3, in particular the phrase “not including notification to the Electric Reliability Organization” which begs the question on whether or not the test requires notifying all the other entities as if it were a real event. This may create confusion in ensuring compliance and during audits. Suggest the SDT to review and modify this requirement as appropriate.
Yes
No
We are unable to comment on the proposed new section as the section does not contain any description of the proposed process or the interface requirements to support the report collecting system. We reserve judgment on this proposal and our right to comment on the proposal when the proposed addition is posted.
We do not agree with the MEDIUM VRF assigned to Requirement R4. Re stipulates a requirement to conduct an annual review of the event reporting Operating Plan in Requirement R1, which itself is assigned a VRF of LOWER. We are unable to rationalize why a subsequent review of a plan should have a higher reliability risk impact than the development of the plan itself. Hypothetically, if an entity doesn’t develop a plan to begin with, then it will be assigned a LOWER VRF, and the entity will have no plan to review annually and hence it will not be deemed non-compliant with requirement R4. The entity can avoid being assessed violating a requirement with a MEDIUM VRF by not having the plan to begin with, for which the entity will be assessed violating a requirement with a LOWER VRF. We suggest changing the R4 VRF to LOWER.
Group
Southern Company Services
Antonio Grayson
No
There are approximately 17 event types for which Responsible Entities must have a process for communicating such events to the appropriate entities and R3 states that “The Responsible Entity shall conduct an annual test of the communications process”. It is likely that the same communications process will be used to report multiple event types, so Southern suggest that the Responsible Entities conduct an annual test for each unique communications process. Southern suggest that this requirement be revised to state “Each Responsible Entity shall conduct an annual

test of each unique communications process addressed in R1.2”. • In Attachment 1, for Event: “Damage or destruction of a Facility”, SDT should consider removing “Results from actual or suspected intentional human action” from the “Threshold for Reporting” column. The basis for this suggestion is as follows: o The actual threshold should be measurable, similar to the thresholds specified for other events in Attachment 1. [Note: The first two thresholds identified (i.e., “Affects and IROL” and “Results in the need for actions to avoid an Adverse Reliability Impact”) are measurable and sufficiently qualify which types of Facility damage should be reported.] o The determination of human intent is too subjective. Including this as a threshold will cause many events to be reported that otherwise may not need to be reported. (e.g., Vandalism and copper theft, while addressed under physical threats, is more appropriately classified as damage. These are generally intentional human acts and would qualify for reporting under the current guidance in Attachment 1. They may be excluded from reporting by the threshold criteria regarding IROLs and Adverse Reliability Impact, if the human intent threshold is removed.) o It may be more appropriate to address human intent in the event description as follows: “Damage or destruction of a Facility, whether from natural or human causes”. Let the thresholds related to BES impact dictate the reporting requirement. • In Attachment 1, for Event: “Complete or partial loss of monitoring capability”, SDT should consider changing the threshold criteria to state: “Affecting a BES control center for ≥ 30 continuous minutes such that analysis capability (State Estimator, Contingency Analysis) is rendered inoperable.” There may be instances where the tools themselves are out of commission, but the control center personnel have sufficiently accurate models and alternate methods of performing the required analyses.
No
It appears that the SDT has incorporated the reporting requirements for CIP-008 “reportable Cyber Security Incidents”; however, the “recognition” requirements remain in CIP-008 Reliability Standard. Southern understands the desire to consolidate reporting requirements into a single standard, but it would be clearer for Cyber Security Incidents if both the recognition and reporting requirements were in one reliability standard and not spread across multiple standards. As it relates to the event type “Loss of Firm Load for > 15 minutes”, Southern suggests that the SDT clarify if weather related loss of firm load is excluded from the reporting requirement. As it relates to the event type “Loss of all voice communication capability”, Southern suggest that the SDT clarify if this means both primary and backup voice communication systems or just primary voice communication systems. Referring to “CIP-008-3 or its successor” in Requirement R1.1 is problematic. This arrangement results in a variable requirement for EOP-004-2 R1. The requirements in a particular version of a standard should be fixed and not variable. If exceptions to applicable events change, a revision should be made to EOP-004 to reflect the modified requirement.
Yes
Move the Background Section (pages 4-9) to the Guideline and Technical Basis section. They are not needed in the main body of the standard. Each “Entity with Reporting Responsibility” in the one-hour reporting table (p. 17) should be explicitly listed in the table, not pointed to another variable location. The criterion for “Threshold for Reporting” in the one-hour reporting table (p. 17) should be explicitly listed in the table, not pointed to another variable location. Please specify the voltage base against which the +/- 10% voltage deviation on a Facility is to be measured in the twenty-four hour reporting table (p. 19).
Individual
John Seelke
Public Service Enterprise Group
Yes
No
We agreed with most of the revisions. However, for the 24-hour reporting time frame portion of the EOP-004 Attachment 1: Reportable Event that starts on p. 18, we have these concerns: a. Why was “RC” left out in the first row? RC is in the second row that also addresses a “Facility.” We believe that “RC” was inadvertently left out. b. In the first row, entities such as a BA, TO, GO, GOP, or DP would not know whether damage or destruction of one of its Facilities either “Affects an IROL (per FAC-014)” or “Results in the need for actions to avoid an Adverse Reliability Impact.” FAC-014-2, R5.1.1 requires Reliability Coordinators provide information for each IROL on the “Identification and status of the

associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL" to entities that do NOT include the entities listed above. And frankly, those entities would not need to know. The reporting requirements associated with "Damage or destruction of a Facility" need to be changed so that the criteria for reporting by an entity whose Facilities experience damage or destruction does not rely upon information that the entity does not possess. c. A possible route to achieve the results in b. above is described below: i. All Facilities that are damaged or destroyed that "Results from actual or suspected intentional human action" would be reported to the ERO by the entity experiencing the damage or destruction. ii. All Facilities that are damaged or destroyed OTHER THAN THAT due to an "actual or suspected intentional human action" would be reported to the RC by the entity experiencing the damage or destruction. Based upon those reports, the RC would be required to report whether the reported damage or destruction of a Facility "Affects an IROL (per FAC-010)" or "Results in the need for actions to Avoid an Adverse Reliability Consequence." (The RC may need to modify its data specifications in IRO-010-1a - Reliability Coordinator Data Specification and Collection - to specify outages due to "damage or destruction of a Facility." We also note that "DP" is not included in IRO-010-1a, but "LSE" is included. DPs are required to also register as LSEs if they meet certain criteria. See the "Statement of Compliance Registry Criteria, Rev. 5.0", p.7. For this reason, we suggest that DP be replaced with LSE in EOP-004-2.) d. To implement the changes in c. above, we suggest that the first row be divided into two rows: i. FIRST ROW: This would be like the existing first row on page 18, except "RC" would be added to the column for "Entity with Reporting Responsibility" and the only reporting threshold would be ""Results from actual or suspected intentional human action." ii. SECOND ROW: The Event would be "Damage or destruction of a Facility of a BA, TO, TOP, GO, GOP, or LSE," the Entity, the Reporting Responsibility would be "The RC that has the BA, TOP, GO, GOP, or LSE experiencing the damage or destruction in its area," and the Threshold for Reporting would be "Affects an IROL (per FAC-010)" or "Results in the need for actions to avoid an Adverse Reliability Consequence."
Yes
Group
Dominion
Connie Lowe
No
While Dominion believes these are positive changes, we are concerned that placing actual calls to each of the "other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement, governmental or provincial agencies" may be seen by one or more of those called as a 'nuisance call'. Given the intent is to insure validity of the contact information (phone number, email, etc), we suggest revising the standard language to support various forms of validation to include, documented send/receipt of email, documented verification of phone number (use of phone book, directory assistance, etc).
Yes
Comments: While Dominion agrees that the revisions are a much appreciated improvement, we are concerned that Attachment 1 does not explicitly contain the 'entities which must be, at a minimum, notified. Attachment 2 appears to indicate that only the ERO and the Reliability Coordinator for the Entity with Reporting Responsibility need be informed. However, the background section indicates that the Entity with Reporting Responsibility is also expected to contact local law enforcement. We therefore suggest that Attachment 2 be modified to include local law enforcement. Page 26 redline; Attachment 1; Event – Damage or destruction of a Facility; Threshold for Reporting – Results from actual or suspected intentional human action; Dominion is concerned with the ambugity that this could be interpreted as applying to distribution. Page 27 redline; Attachment 1; Event – Any physical threat that could impact the operability of a Facility; Dominion is concerned the word "could" is hypothetical and therefore unverifiable and un-auditable. The SDT could provide a list of hypothetical "could impact" events, as well as a specific definition and method for determining a specific physical impact threshold for "could impact" events other than "any."
Yes
While Dominion supports this addition, we suggest adding to the sentence "NERC will establish a system to collect report forms as established for this section or reliability standard….."

Dominion believes that the reporting of “Any physical threat that could impact the operability of a Facility4” may overwhelm the Reliability Coordinator staff with little to no value since the event may have already passed. This specific event uses the phrase “operability of a Facility” yet “operability” is not defined and is therefore ambiguous. We do support the reporting to law enforcement and the ERO but do not generally support reporting events that have passed to the Reliability Coordinator. Attachment 2; section 4 Event Identification and Description: The type of events listed should match the events as they are exactly written in Attachment 1. As it is currently written, it leaves room for ambiguity. M3 – Dominion objects to having to provide additional supplemental evidence (i.e. operator logs), and the SDT maybe want to include a requirement for NERC to provide a confirmation that the report has been received.
Individual
Terry Harbour
MidAmerican Energy
No
See the NSRF comments. The real purpose of this requirement appears to be to assure operators are trained in the use of the procedure, process, or plan that assures proper notification. PER-005 already requires a systematic approach to training. Reporting to other affected entities is a PER-005 system operator task. Therefore this requirement already covered by PER-005 and is not required. Organizations are also required to test their response to events in accordance with CIP-008 R1.6. Therefore this requirement is covered by other standards and is not needed. Inclusion of this standard would place entities in a double or possible triple jeopardy. The SDT may need to expand M3 reporting options, by stating “… that the annual test of the communication process of 1.2 (e.g. communication via e-mail, fax, phone, ect) was conducted”. R4 is an administrative requirement with little reliability value and should be deleted. It would likely be identified as a requirement that that should be eliminated as part of the request by FERC to identify strictly administrative requirements in FERC’s recent order on FFTR.
No
Several modifications need to be made to Table 1 to enhance clarity and delete unnecessary or duplicate items. The stated reliability objective of EOP-004 and the drafting team is to reduce and prevent outages which could lead to cascading through reporting. It is understood that the EOP-004 Attachment 1 is to cover similar items to the DOE OE-417 form. Last, remember that FERC recently asked the question of what standards did not provide system reliability benefits. Those reports that cannot show a direct threat to a potential cascade need to be eliminated. Table 1 should always align with the cascade risk objectives and OE-417 where possible. Therefore Table 1 should be modified as follows: 1. Completely divorce CIP-008 from EOP-004. Constant changes, the introduction of new players such as DOE and DHS, and repeated congressional bills, make coordination with CIP-008 nearly impossible. Cyber security and operational performance under EOP-004 remain separate and different despite best efforts to combine the two concepts. 2. Modify R1.2 to state that ERO notification only is required for Table 1. This is similar to the DOE OE-417 notification. Notification of other entities is a best practice, not a mandatory NERC standard. If entities want to notify neighboring entities, they may do so as a best practice guideline. 3. Better clarity for communicating each of the applicable events listed in the EOP-004 Attachment 1 in accordance with the timeframes specified are needed. MidAmerican suggests a forth column be added to the table to clearly identify who must be notified within the specified time period or at a minimum, that R1.2 be revised to clearly state that only the ERO must be notified to comply with the standard. 4. Consolidate OE-417 concepts on physical attack and cyber events by consolidating OE-417 items 1, 2, 9 and 10 to: Verifiable, credible, and malicious physical damage (excluding natural weather events) to a BES generator, line, transformer, or bus that when reported requires an appropriate Reliability Coordinator or Balancing Authority to issue an Energy Emergency Alert Level 2 or higher. The whole attempt to discuss a NERC Facility and avoid adverse reliability impacts overreaches the fundamental principal or reporting for an emergency that could result in a cascade. 5. The wording “affects an IROL (per FAC-014),” is too vague and not measurable. Many facilities could affect an IROL, but fewer facilities if lost would cause an IROL. Change “affects” to “results in” 6. Recommend that Adverse Reliability Impact be deleted and be replaced with actual EEA 2 or EEA 3 level events. 7. The phrase “results from actual or suspected intentional human action” is vague and not measurable. This line item used the term “suspected” which relates to “sabotage”. MidAmerican recommends that “Results from actual or suspected intentional human action” be deleted. If not deleted the phrase should be replaced with

“Results from verifiable, credible, and malicious human action intended to damage the BES.” 8. Delete “Any physical threat…” as vague, and difficult to measure in a “perfect” zero defect audit environment, and as already covered by item 1 above. If not deleted, at a minimum replace “Any physical threat”, with “physical attack” as being measureable and consistent with DOE OE-417. 9. With the use of “i.e.” the SDT is mandating that each other entity must be contacted. The NSRF believes that the SDT meant that “e.g.” should be used to provide examples. The SDT may wish to add another column to Attachment 1 to provide clarity. 10. The phrase “or partial loss of monitoring capability” is too vague and should be deleted. In addition, the 30 minute window is too short for EMS and IT staff to effectively be notified and troubleshoot systems before being subjected to a federal law requiring reporting and potential violations. The time frame should be consistent with the EOP-008 standard. If not deleted, replace with “Complete loss of SCADA affecting a BES control center for ≥ 60 continuous minutes such that analysis tools of State Estimator and/or Contingency Analysis are rendered inoperable. 11. Transmission loss should be deleted. The number of transmission elements out does not directly correlate to BES stability and cascading. For that reason alone, this item should be deleted or it would have already been included in the past EOP-004 standard. In addition, large footprints can have multiple storms or weather events resulting in normal system outages. This should not be a reportable event that deals with potential cascading. 12. Modify the threshold of “BES emergency requiring a public appeal…” to include, “Public appeal for a load reduction event resulting from a RC or BA implementing its emergency energy and capcity plans documented in EOP-001.” Public appeals for conservation that aren't used to avoid capacity and energy emergencies should be clearly excluded. 13. Add a time threshold to complete loss of off-site power to a nuclear plant. Nuclear plants are to have backup diesel generation that last for a minimum amount of time. A threshold recognizing this 4 hour or longer window needs to be added such as complete loss of off-site power to a nuclear plant for more than 4 hours. Also see the NSRF comments.
No
See the NSRF comments. The NERC Rules of Procedure Section 807 already addresses the dissemination of Disturbance data, as does Appendix 8 Phase 1 with the activation of NERC’s crisis communication plan, and the ESISAC Concept of Operations. The addition of proposed Section 812 is not necessary. The Reliability Coordinator, through the use of the RCIS, would disseminate reliability notifications if it is in turn notified per R1.2. (As stated in the in the Clean copy of EOP-004-2)
See the NSRF comments.
Individual
Brenda Lyn Truhe
PPL Electric Utilities
Yes
Yes
PPL EU thanks the SDT for the changes made in this latest proposal. We feel our prior comments were addressed. Regarding the event 'Transmission Loss': For your consideration, please consider adding a footnote to the event ‘Transmission Loss’ such that weather events do not need to be reported. Also please consider including 'operation contrary to design' in the threshold language. E.g. consistent with the NERC Event Analysis table, the threshold would be, ‘Unintentional loss, contrary to design, of three or more BES Transmission Facilities.’
Yes
We appreciate the inclusion of the Process Flowchart on Page 9 of the draft standard. We submit for your consideration, removing the line from the NO decision box to the ‘Report Event to ERO, Reliability Coordinator’ box. It seems if the event does not need reporting per the decision box, this line is not needed. For clarity in needed actions, please consider using a decision box following flowcharting standards such as, a decision box containing a question with a Yes and a No path. The decision box on ‘Report to Law Enforcement ?’ does not have a Yes or No. Perhaps, this decision box is misplaced, or is it intended to occur always and not have a different path with different actions? Ie. should it be a process box? Thank you for your work on this standard.
Individual
John Martinsen

Public Utility District No. 1 of Snohomish County
Yes
This is an excellent improvement over the prior CIP and EOP versions. However, please see #4 for overall comment.
This is an excellent improvement over the prior CIP and EOP versions. However, please see #4 for overall comment.
No
This type of activity and process is better suited to NAESBE than it is to NERC Compliance.
SNPD suggest moving these administrative activities to NAESB. R1: There is merit in having a plan as identified in R1, but is this a need to support reliability or is it a business practice? Should it be in NAESB's domain? R2, R3 & R4: These are not appropriate for a Standard. If you don't annually review the plan, will reliability be reduced and the BES be subject to instability, separation and cascading? If DOE needs a form filled out, fill it out and send it to DOE. NERC doesn't need to pile on. Gerry Cauley and Mike Moon have been stressing results and risk based, actual performance based, event analysis, lessons learned and situational awareness. EOP-004 is primarily a business preparedness topic and identifies administrative procedures that belong in the NAESB domain.
Individual
Russell A. Noble
Cowlitz County PUD
Yes
Yes
Yes
Cowlitz is pleased with changes made to account for the difficulties small entities have in regard to reporting time frames. Although Cowlitz is confident that the current draft is manageable for small entities, we propose that the resulting reports this Standard will generate will contain many insignificant events from the event types "Damage or destruction of a Facility," and "Any physical threat that could impact the operability of a Facility." In particular, examples would be limited target practice on insulators, car-pole accidents, and accidental contact from tree trimming or construction activities. Cowlitz suggests that at least a >= 100 MW (200 MW would be better) and/or >= N-2 impact threshold be established for these event types. Also, Cowlitz suggests the statement "results from actual or suspected intentional human action" be changed to "results from actual or suspected intentional human action to damage or destroy a Facility." A human action may be intentional which can result in damage to a facility, but the intent may have been of good standing, and not directed at the Facility. For example, the intent may have been to legally harvest a tree, or move equipment under a line. Cowlitz believes the above proposed changes would benefit the ERO, both in reduction of nuisance reports and possible violations over minimal to no impact BES events.
Group
SPP Standards Review Group
Robert Rhodes
No
There needs to be a more granular definition of which entities should be included in the annual testing requirement in R3. To clarify what must be tested we propose the following language to replace the last sentence in M3. The annual test requirement is considered to be met if the responsible entity implements any communications process in the Operating Plan during an actual event. If no actual event was reported during the year, at least one of the communication processes in the Operating Plan must be tested to satisfy the requirement. We do not believe the time-stamping requirement in M3 and M4 contribute to the reliability of the BES. A dated review should be sufficient.
No
To obtain an understanding of the drivers behind the events in Attachment 1, we would like to see where these events come from. If the events are required in standards, refer to them. If they are in

the existing event reporting list, indicate so. If they are coming from the EAP, let us know. We have a concern that, as it currently exists, Attachment 1 can increase our reporting requirements considerably. We also have concerns about what appears to be a lack of coordination between EAP reporting requirements and those contained in Attachment 1. For example, the EAP reporting requirement is for the complete loss of monitoring capability whereas Attachment 1 adds the requirement for reporting a partial loss of monitoring capability. It appears that some of the EAP reporting requirements are contained in Attachment 1. We have concerns that this is beyond the scope of the SAR and should not be incorporated in this standard. We have concern with several of the specific event descriptions as contained in Attachment 1: Damage or destruction of a Facility – We are comfortable with the proposed definition of Adverse Reliability Impact but have concerns with the existing definition of ARI. Any physical threat that could impact the operability of a Facility1 – We take exception to this event in that is goes beyond what is currently required in EOP-004-1, including DOE reporting requirements, and the EAP reporting requirements. We do not understand the need for this event type and object to the potential for excessive reporting required by such an event type. Additionally, we are concerned about the potential for multiple reporting of a single event. This same concern applies to several other events including Damage or destruction of a Facility, Loss of firm load for ≥ 15 minutes, System separation, etc. When multiple entities are listed as the Entity with Reporting Responsibility, Attachment 1 appears to require each entity in the hierarchy to submit a report. There should only be one report and it should be filed by the entity owning the event. The SDT addressed this issue in its last posting but the issue still remains and should be reviewed again. BES Emergency resulting in automatic firm load shedding – For some reason, not stipulated in the Consideration of Comments, the action word in the Entity with Reporting Responsibility was changed from ‘experiences’ to ‘implements’. We recommend changing it back to ‘experiences’. Automatic load shedding is not implemented. It does not require human intervention. It’s automatic. Voltage deviation on a Facility – Similar to the comment on automatic load shedding above, the action word was changed from ‘experiences’ to ‘observes’. We again recommend that it be changed back to ‘experiences’. Using observes obligates a TOP, who is able to see a portion of a neighboring TOP’s area, to submit a report if that TOP observed a voltage deviation in the neighboring TOP’s area. The only reporting entity in this event should be the TOP within whose area the voltage deviation occurred. Complete or partial loss of monitoring capability – Clarification on partial loss of monitoring capability and inoperable are needed. Also, the way the Threshold is written, it implies that a State Estimator and Contingency Analysis are required. To tone this down, insert the qualifier ‘such as’ in front of State Estimator.
No
We have two concerns about the proposed change to the RoP. One, we have concerns that our information and data will be circulated to an as yet undetermined audience which appears to be solely under NERC’s control. Secondly, there isn’t sufficient detail in the clearinghouse concept to support comments at this time.
The VRF for R1 is Lower which is fine. The issue is that R4, which is the review of the plan contained in R1, has a Medium VRF. We recommend moving the VRF of R4 to Lower. We recommend deleting the phrase ‘…supplemented by operator logs or other operating documentation…’ as found in the first sentence of M2. A much clearer reference is made to operator logs and other operating documentation in the second sentence. The duplication is unnecessary. What will happen with the accompanying information contained in the Background section in the draft standard? Will it be moved to the Guideline and Technical Basis at the end of the standard as the information contained in the text boxes? This is valuable information and should not be lost.
Group
Florida Municipal Power Agency
Frank Gaffney
No
First, FMPA believes the standard is much improved from the last posting and we thank the SDT or their hard work. Having said that, there are still a number of issues, mostly due to ambiguity in terms, which cause us to vote Negative. R3 and R4 should be combined into a single requirement with two subparts, one for annual testing, and another to incorporate lessons learned from the annual testing into the plan (as opposed to an annual review). The word “test” is ambiguous as used in R3, e.g., does a table top drill count as a “test”? Is the intent to “test” the plan, or “test” the phone

numbers, or what?
No
The bullet on “any physical threat” is un-measurable. What constitutes a “threat”? FMPA likes the language used in the comment form discussing this item concerning the judgment of the Responsible Entity, but, the way it is worded in Attachment 1 will mean the judgment of the Compliance Enforcement Authority, not the Responsible Entity. Presumably, the Responsible Entity will need to develop methods to identify physical threats in accordance with R1; hence, FMPA suggests rewording to: “Any physical threat recognized by the Responsible Entity through processes established in R1 bullet 1.1”. We understand this introduces circular logic, but, it also introduces the “judgment of the Responsible Entity” into the bullet. On the row of the table on voltage deviation, replace the word “observes” with “experiences”. It is possible for one TOP to “observe” a voltage deviation on another TOP’s system. It should be the responsibility of the TOP experiencing the voltage deviation on its system to report, not the one who “observes”. One the row on islanding, it does not make sense to report islanding for a system with load less than the loss of load metrics and we suggest using the same 300 MW threshold for a reporting threshold. One the row on generation loss, some clarification on what type of generation loss (especially in the time domain) would help it be more measurable, e.g., concurrent forced outages. One the row on transmission loss, the same clarity is important, e.g., three or more concurrent forced outages. On the row on loss of monitoring, while FMPA likes the threshold for “partial loss of monitoring capability” for those systems that have State Estimators, small BAs and TOPs will not need or have State Estimators and the reporting threshold becomes ambiguous. We suggest adding something like loss of monitoring for 25% of monitored points for those BAs and TOPs that do not have State Estimators.
Yes
In R1, bullet, it is a bit ambiguous whether the list of organizations to be communicated with is an exhaustive list (i.e.) or a list of examples (e.g.). The list is preceded by an “i.e.” which indicates the former, but includes an “or” which indicates the latter. We are interpreting this as meaning the list is exhaustive as separated by semi-colons, but that the last phrase separated by commas is a list of examples. Is this the correct interpretation? The Rules of Procedure language for data retention (first paragraph of the Evidence Retention section) should not be included in the standard, but instead referred to within the standard (e.g., “Refer to Rules of Procedure, Appendix 4C: Compliance Monitoring and Enforcement Program, Section 3.1.4.2 for more retention requirements”) so that changes to the RoP do not necessitate changes to the standard.
Group
LG&E and KU Services
Brent Ingebrigtson
Yes
No
The SDT should consider more clearly defining the Threshold for Reporting for the Event: “Any physical threat that could impact the operability of a Facility” to only address those events that have an Adverse Reliability Impact. Some proposed language might be: “Threat to a Facility excluding weather related threats that could result in an Adverse Reliability Impact.” For those events specifically defined in the ERO Events Analysis Process, the SDT should consider revising the language to be more consistent with the language included in the ERO Events Analysis Process. Here is some recommended language: 1. EVENT: Transmission loss THRESHOLD FOR REPORTING: “Unintentional loss, contrary to design, of three or more BES Transmission Facilities (excluding successful automatic reclosing) caused by a common disturbance. 2. EVENT: “Complete or partial loss of monitoring capability” – could be revised to read “Complete loss of SCADA control or monitoring functionality” THRESHOLD FOR REPORTING: “Affecting a BES control center for ≥ 30 continuous minutes such that analysis tools (e.g. State Estimator, Contingency Analysis) are rendered inoperable”.
Yes
The Violation Severity Level for Requirement R2 should be revised to read “...hours after recognizing an event requiring reporting...” This will make the language in the VSL consistent with the language in

Attachment 1.
Individual
Thomas Washburn
FMPP
See FMPA's comments
Group
MRO NSRF
WILL SMITH
No
R3 states: Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2. R1.2 states: A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement, governmental or provincial agencies. With the use of "i.e." the SDT is mandating that each other entity must be contacted. The NSRF believes that the SDT meant that "e.g." should be used to provide examples. The SDT may wish to add another column to Attachment 1 to provide clarity. R3 requires and annual test that would include notification of: "other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement, governmental or provincial agencies." Since NERC see no value in receiving these test notification we are doubtful other entities identified in R1.2 would find them of value. The real purpose of this requirement appears to be to assure operators are trained in the use of the procedure, process, or plan that assures proper notification. PER-005 already requires a systematic approach to training. It is hard to comprehend an organization not identifying this as a Critical Task, and if they failed to identify it as a Critical Task that this would not be a violation. Therefore this requirement is not required. Furthermore organizations test their response to events in accordance with CIP-008 R1.6. Therefore this requirement is covered by other standards and is not needed. The SDT may need to address this within M3, by stating "… that the annual test of the communication process of 1.2 (e.g. communication via e-mail, fax, phone, ect) was conducted". R4 states: Each Responsible Entity shall conduct an annual review of the event reporting Operating Plan in Requirement R1. We question the value of requiring an annual review. If the Standard does not change, there seems little value in requiring an annual review. This appears to be an administrative requirement with little reliability value. It would likely be identified as a requirement that that should be eliminated as part of the request by FERC to identify strictly administrative requirements in FERC's recent order on FFTR. We suggest it be eliminated.
No
R1.2 states: A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement, governmental or provincial agencies. This implies not only does NERC need to be notified within the specified time period but that: "other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement, governmental or provincial agencies." are also required to be notified within in the time periods specified. We suggest a forth column be added to the table to clearly identify who must be notified within the specified time period or that R1.2 be revised to clearly state that only NERC must be notified to comply with the standard. With the use of "i.e." the SDT is mandating that each other entity must be contacted. The NSRF believes that the SDT meant that "e.g." should be used to provide examples. The SDT may wish to add another column to Attachment 1 to provide clarity. Also with regards to Attachment 1, the following comments are provided: 1. Instead of referring to CIP-008 (in the 1 hour reporting section), quote the words from CIP-008, this will require coordination of future revisions but will assure clarity

in reporting requirements. 2 Under “Damage or destruction of a Facility” a. The wording “affects an IROL (per FAC-014),” is too vague. Many facilities could affect an IROL, not as many if lost would cause an IROL. b. Adverse Reliability Impact is defined as: “The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.” There are an infinite number of routine events that result in the loss of generation plants due to inadvertent actions that somehow also damaged equipment. Any maintenance activity that damaged a piece of equipment that causes a unit to trip or results in a unit being taken off line in a controlled manner would now be reportable. This seems to be an excessive reporting requirement. Recommend that Adverse Reliability Impact be deleted and be replaced with actual EEA 2 or EEA 3 level events. c. The phrase “Results from actual or suspected intentional human action.” This line item used the term “suspected” which relates to “sabotage”. Recommend the following: Results from actual or malicious human action intended to damage the BES. 3. “Any physical threat that could impact the operability of a Facility1” The example provided by the drafting team of a train derailment exemplifies why this requirement should be deleted. A train derailment of a load of banana’s more than likely would not threaten a nearby BES Facility. However a train carrying propane that derails carrying propane could even if it were 10 miles away. Whose calculation will be used to determine if an event could have impacted the asset? As worded there is too much ambiguity left to the auditor. We suggest the drafting team clarify by saying “Any event that requires the a BES site be evacuated for safety reasons” Furthermore if weather events are excluded, we are hard pressed to understand why this information is important enough to report to NERC. So barring an explanation of the purpose of this requirement, including why weather events would be excluded, we suggest the requirement be deleted. Please note that if you align this with “Physical attack” with #1 of the OE-417. This clearly states what the SDT is looking for. 4. The phrase “or partial loss of monitoring capability” is too vague. Further definitions of “inoperable” are required to assure consistent application of this requirement. Recommend that “Complete loss of SCADA affecting a BES control center for ≥ 30 continuous minutes such that analysis tools of State Estimator and/or Contingency Analysis are rendered inoperable. Or, Complete loss of the ability to perform a State Estimator or Contingency Analysis function, the threshold of 30 mins is too short. A 60 min threshold will align with EOP-008-1, R1.8. Since this is the time to implement the contingency back up control center plan. 5. Event: Voltage deviation on a Facility. ATC believes that the term “observes” for Entity with Reporting Responsibility be changed back to “experiences” as originally written. The burden should rest with the initiating entity in consistency with other Reporting Responsibilities. Also, for Threshold for Reporting, ATC believes the language should be expanded to - plus or minus 10% ”of target voltage” for greater than or equal to 15 continuous minutes. 6. Event: Transmission loss. ATC recommends that Threshold for Reporting be changed to read “Unintentional loss of four, or more Transmission Facilities, excluding successful automatic reclosing, within 30 seconds of the first loss experienced and for 30 continuous minutes. Technical justification or Discussion for this recommended change: In the instance of a transformer-line-transformer, scenario commonly found close-in to Generating stations, consisting of 3 defined “facilities”, 1 lightning strike can cause automatic unintentional loss by design. Increase the number of facilities to 4. In a normal shoulder season day, an entity may experience the unintentional loss of a 138kv line from storm activity, at point A in the morning, a loss of a 115kv line from a different storm 300 miles from point A in the afternoon, and a loss of 161kv line in the evening 500 miles from point A due to a failed component, if it is an entity of significant size. Propose some type of time constraint. Add time constraint as proposed, 30 seconds, other than automatic reclosing. In the event of dense lightning occurrence, the loss of multiple transmission facilities may occur over several minutes to several hours with no significant detrimental effect to the BES, as load will most certainly be affected (lost due to breaker activity on the much more exposed Distribution system) as well. Any additional loss after 30 seconds must take into account supplemental devices with intentional relay time delays, such as shunt capacitors, reactors, or load tap changers on transformers activating as designed, arresting system decay. In addition, Generator response after this time has significant impact. Please clarify or completely delete why this is included within this version when no basis has been give and it is not contained w3ithin the current enforceable version. 7. Modify the threshold of “BES emergency requiring a public appeal…” to include, “Public appear for a load reduction event resulting for a RC or BA implementing its emergency operators plans documented in EOP-001.” The reason is that normal public appeals for conservation should be clearly excluded. 8. Add a time threshold to complete loss of off-site power to a nuclear plant. Nuclear plants are to have backup diesel generation that last for a minimum amount of time. A threshold recognizing this 4 hour or

longer window needs to be added such as complete loss of off-site power to a nuclear plant for more than 4 hours. 9. Delete “Transmission loss”. The loss of a specific number of elements has no direct bearing on the risk of a system cascade. Faults and storms can easily result in “unintentional” the loss of multiple elements. This is a flawed concept and needs to be deleted
Yes
ATC believes that the NERC Rules of Procedure Section 807 already addresses the dissemination of Disturbance data, as does Appendix 8 Phase 1 with the activation of NERC’s crisis communication plan, and the ESISAC Concept of Operations. The addition of proposed Section 812 is not necessary. The Reliability Coordinator, through the use of the RCIS, would disseminate reliability notifications if it is in turn notified per R1.2. (As stated in the in the Clean copy of EOP-004-2)
R1 states: “Each Responsible Entity shall have an event reporting Operating Plan that includes:” The definition of Operating Plan is: “A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.” This appears to us to be too prescriptive and could be interpreted to require a series of documents to for reporting issues to NERC. We suggest the following wording: R1. Each Responsible Entity shall have document methodology(ies) or process(es) for: 1.1. Recognizing each of the applicable events listed in EOP-004 Attachment 1. 1.2. Reporting each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization. LES Comment: [R1] We are concerned by the significant amount of detail an entity would be required to contain within the Operating Plan as part of Requirement R1. Rather than specifying an entity must have a documented process for recognizing each of the events listed in EOP-004-2 Attachment 1, at a minimum, consider removing the term “process” in R1.1 and replacing with “guideline” to ensure operating personnel are not forced to adhere to a specific sequence of steps and still have the flexibility to exercise their own judgment. Section 5 of the standard (Background) should be moved to the Guideline and Technical Basis document. A background that long does not belong in the standard piece as it detracts from the intent of the standard itself.
Group
Progress Energy
Jim Eckelkamp
No
It should be clear that the Operating Plan can be multiple procedures. It is an unnecessary burden to have entities create a new document outlining the Operating Plan. Having to create a new Operating Plan would not improve reliability and would further burden limited resources. The annual testing required by R3 should be clarified. Do all communication paths need to be annually tested or just one path? An actual event may only utilize one communication 'leg' or 'path' and leave others untested and untilized. Entities may have a corporate level procedure that 'hand-shakes' with more localized procedures that make up the entire Operating Plan. Must all communications processes be tested to fulfill the requirement? If an entity has 'an actual event' it is not necessarily true that their Operating Plan has been exercised completely, yet this one 'actual event' would satisfy M3 as written.
Within attachment 1 (Reportable Events) an exclusion is allowed for weather related threats. PGN recommends a more generic approach to include natural events such as forest fires, sink holes, etc. This would alleviate some reporting burdens in areas that are prone to these types of events.
Individual
Bob Thomas
Illinois Municipal Electric Agency
No
IMEA reluctantly (in recognition of the SDT's efforts and accomplishments to date) cast a Negative vote for this project primarily based on R3 because it is attempting to fix a problem that does not exist and impacts small entity resources in particular. IMEA is not aware of seeing any information regarding a trend, or even a single occurance for that matter, in a failure to report an event due to

failure in reporting procedures. A small entity is less likely to experience a reportable event, and therefore is less likely to be able to take advantage of the provision in M3 to satisfy the annual testing through imiplementation of an actual event. If there is a problem that needs to be fixed, it would make much more sense to replace the language in R3 with a simple requirement for the RC, BA, IC, TSP, TOP, etc. to inform the TO, DP, LSE if there is a change in contact information for reporting an event. It is hard to believe that an RC, BA, IC, TSP, TOP, etc. is going to want to be annually handling numerous inquiries from entities regarding the accuracy of contact information. The impact of unnecessary requiements on entity resources, particularly small entities', is finally starting to get some meaningful attention at NERC and FERC. It would be a mistake to adopt another unnecessary requirement as currently specified in R3.
No
Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency.
No
Illinois Municipal Electric Agency supports comments submitted by ATC.
Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency.
Individual
Andrew Z. Pusztai
Amercican Transmission Company, LLC
No
ATC recommends eliminating R4 altogether. If R3, the annual test, is conducted as part of the Operating Plan, R4 is merely administrative, and does not add value to reliability.
No
ATC is proposing changes to the following Events in Attachment 1: (Reference Clean Copy of the Standard) 1) Pg. 18/ Event: Any Physical threat that could impact the operability of a Facility. ATC is proposing a language change to the Threshold- “Meets Registered Entities criteria stated in its Event Reporting Operating Plan, in addition to excluding weather.” 2) Pg. 19 / Event: Voltage deviation on a Facility. ATC believes that the term “observes” for Entity with Reporting Responsibility be changed back to “experiences” as originally written. The burden should rest with the initiating entity in consistency with other Reporting Responsibilities. Also, for Threshold for Reporting, ATC believes the language should be expanded to - plus or minus 10% ”of target voltage” for greater than or equal to 15 continuous minutes. 3) Pg. 19/ Event: Transmission loss. ATC recommends that Threshold for Reporting be changed to read “Unintentional loss of four, or more Transmission Facilities, excluding successful automatic reclosing, within 30 seconds of the first loss experienced and for 30 continuous minutes. Technical justification or Discussion for this recommended change: In the instance of a transformer-line-transformer, scenario commonly found close-in to Generating stations, consisting of 3 defined “facilities”, 1 lightning strike can cause automatic unintentional loss by design. Increase the number of facilities to 4. In a normal shoulder season day, an entity may experience the unintentional loss of a 138kv line from storm activity, at point A in the morning, a loss of a 115kv line from a different storm 300 miles from point A in the afternoon, and a loss of 161kv line in the evening 500 miles from point A due to a failed component, if it is an entity of significant size. Propose some type of time constraint. Add time constraint as proposed, 30 seconds, other than automatic reclosing. In the event of dense lightning occurrence, the loss of multiple transmission facilities may occur over several minutes to several hours with no significant detrimental effect to the BES, as load will most certainly be affected (lost due to breaker activity on the much more exposed Distribution system) as well. Any additional loss after 30 seconds must take into account supplemental devices with intentional relay time delays, such as shunt capacitors, reactors, or load tap changers on transformers activating as designed, arresting system decay. In addition, Generator response after this time has significant impact. 4) Pg.20 /Event: Complete or partial loss of monitoring capability. ATC recommends that the term “partial” be deleted from the event description. ATC recommends that the term “partial” be deleted for the Entity with Reporting Responsibility and changed to read: Each RC, BA, and TOP that experiences the complete loss of monitoring capability.
No
ATC believes that the NERC Rules of Procedure Section 807 already addresses the dissemination of Disturbance data, as does Appendix 8 Phase 1 with the activation of NERC’s crisis communication plan, and the ESISAC Concept of Operations. The addition of proposed Section 812 is not necessary.

The Reliability Coordinator, through the use of the RCIS, would disseminate reliability notifications if it is in turn notified per R1.2. (As stated in the in the Clean copy of EOP-004-2)
Individual
Brenda Frazer
Edison Mission Marketing & Trading, Inc.
Yes
Yes
Yes
No
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
Yes
No
1.) PPL Generation thanks the SDT for the changes made in this latest proposal. We feel our previous comments were addressed. PPL Generation offers the following additional comments. Regarding the event 'Transmission Loss': For your consideration, please consider adding a footnote to the event 'Transmission Loss' such that weather events do not need to be reported. Also please consider including operation contrary to design in the language and not just in the example. E.g. consistent with the NERC Event Analysis table, the threshold would be, 'Unintentional loss, contrary to design, of three or more BES Transmission Facilities.' 2.) PPL Generation proposes the following changes in Attachment 1 to the first entry in the "Threshold for Reporting" column to make it clear that independent GO/GOPs are required to act only within their sphere of operation and based on the information that is available to the GO/GOPs: Damage or destruction of a Facility that: Affects an IROL (per FAC-014, not applicable to GOs and GOPs) OR Results in the need for actions to avoid an Adverse Reliability Impact (not applicable to GOs and GOPs) OR Results from actual or suspected intentional human action (applicable to all).
Yes
We appreciate the inclusion of the Process Flowchart on Page 9 of the draft standard. We submit for your consideration, removing the line from the NO decision box to the 'Report Event to ERO, Reliability Coordinator' box. It seems if the event does not need reporting per the decision box, this line is not needed. The decision box on 'Report to Law Enforcement ?' does not have a Yes or No. Perhaps, this decision box is misplaced, or is it intended to occur always and not have a different path with different actions? Ie. should it be a process box? Thank you for your work on this standard.
Individual
Kenneth A Goldsmith
Alliant Energy
No
In the first Event for twenty four hour reporting, the last item in "Threshold for Reporting" should be revised to "Results from actual or suspected intentional malicious human action." An employee may be performing maintenance and make a mistake, which could impact the BES. In the second Event for twenty four hour reporting the event should be revised to "Any physical attack that could impact the operability of a Facility." Alliant Energy believes this is clearer and easier to measure.
Section 5 of the standard (Background) should be moved to the Guideline and Technical Basis

document. A background that long does not belong in the standard piece as it detracts from the intent of the standard itself.
Individual
Eric Salsbury
Consumers Energy
No
The term "Facility" seems to be much more broad and even more vague than the use of BES equipment. We recommend reverting back to use of BES equipment.
Group
Hydro One
Sasa Maljukan
No
In the Requirement R3, we suggest adding the following wording from Measure M3 to the end of R3 after the wording “in Part 1.2.”: The annual test requirement is considered to be met if the responsible entity implements the communications process in Part 1.2 for an actual event. This language must be in the Requirement to be considered during an audit. Measures are not auditable. Statement “... not including notification to the ERO...” as it stands now is confusing. We suggest that this statement is either reworded (and explained in the Rational for this requirement) or outright removed for clarity purposes In the requirement R4, we suggest replacing the words “an annual review” with the words “a periodic review.” Add the following to R4: The frequency of such periodic reviews shall be specified in the Operating Plan and the time between periodic reviews shall not exceed five (5) years. This does not preclude an annual review in an Entity’s operating plan. The Entity will then be audited to its plan. If the industry approves a five (5) year periodic review ‘cap,’ and FERC disagrees, then FERC will have to issue a directive, state it reasons and provide justification for an annual review that is not arbitrary or capricious. Adding the one year “test” requirement adds to the administrative tracking burden and adds no reliability value. The table in the standard is clear regarding what events need to be reported. An auditor may want to see a test for "each" of the applicable events listed in EOP-004 Attachment 1.If the requirement for "an" annual test remains in the standard in R3, then it should be made clear that a test is not required for "each" of the applicable events listed in Attachment 1 (reference to R1.2.)
No
In the Attachment 1, language identical to event descriptions in the NERC Event Analysis Process and FERC OE-417 should be used. Creating a third set of event descriptions is not helpful to system operators. Recommend aligning the Attachment 1 wording with that contained in Attachment 2, DOE Form OE-417 and the EAP whenever possible. The proposed “events” are subjective and will lead to confusion and questions as to what has to be reported. - Event: A reportable Cyber Security Incident. All reportable Cyber Security Incidents may not require “One Hour Reporting.” A “one-size fits all” approach may not be appropriate for the reporting of all Cyber Security Incidents. The NERC “Security Guideline for the Electricity Sector: Threat and Incident Reporting” document provides time-frames for Cyber Security Incident Reporting. For example, a Cyber Security Compromise is recommended to be reported within one hour of detection, however, Information Theft or Loss is recommended to be reported within 48 hours. Recommend listing the Event as “A confirmed reportable Cyber Security Incident. The existing NERC “Security Guideline for the Electricity Sector: Threat and Incident Reporting” document uses reporting time-frames based on “detection” and “discovery.” Recommend using the word confirmed because of the investigation time that may be required from the point of initial “detection” or “discovery” to the point of confirmation, when the compliance “time-clock” would start for the reporting requirement in EOP-004-2. - Event: Damage or destruction of a Facility Threshold for Reporting: revise language on third item to read: “Results from actual or suspected intentional human action, excluding unintentional human errors”. - Event: Any physical threat that could impact the operability of a Facility This Event category should be deleted. The word “could” is hypothetical and therefore unverifiable and un-auditable. The word “impact” is undefined. Please delete this reporting requirement, or provide a list of hypothetical “could impact” events, as well as a

specific definition and method for determining a specific physical impact threshold for “could impact” events other than “any.” - Event: BES Emergency requiring public appeal for load reduction. Replace wording in the Event column with language from #8 on the OE-417 Reporting Form to eliminate reporting confusion. Following this sentence add, “This shall exclude other public appeals, e.g., made for weather, air quality and power market-related conditions, which are not made in response to a specific BES event.” - Event: Complete or partial loss of monitoring capability Event wording: Delete the words “or partial” to conform the wording to the NERC Event Analysis Process. - Event: Transmission Loss Revise to BES Transmission Loss - Event: Generation Loss Revise to BES Generation Loss
No
The proposed new section does not contain specifics of the proposed system nor the interfacing outside of the system to support the report collecting.
The proposed standard is not consistent with NERC’s new Risk Based Compliance Monitoring. - The performance based action to “implement its event reporting Operating Plan” on defined events, as required in R2, could be considered a valid requirement. However, the concern is that this requirement could be superseded by the NERC Events Analysis Process and existing OE-417 Reporting. - The requirements laid out in R1, R3 and R4 are specific controls to ensure that the proposed requirement to report (R2) is carried out. However, controls should not be part of a compliance requirement. The only requirement proposed in this standard that is not a control is R2. NERC does not need to duplicate the enforcement of reporting already imposed by the DOE. DOE-417 is a well-established process that has regulatory obligations. NERC enforcement of reporting is redundant. NERC has the ability to request copies of these reports without making them part of the Reliability Rules. Form EOP-004, Attachment 2: Event Reporting Form: - Delete from the Task column the words “or partial”. - Delete from the Task column the words “physical threat that could impact the operability of a Facility”. VSL’s may have to be revised to reflect revised wording. The standard as proposed is not supportive of Gerry Cauley’s performance based standard initiative
Group
CenterPoint Energy
John Brockhan
No
CenterPoint Energy recommends that “and implement” be added after “Each Responsible Entity shall have” in Requirement R1. After such revision, Requirement R2 will not be needed as noted in previous comments submitted by the Company. CenterPoint Energy also believes that Requirement R3 is not needed as an annual review encompassing the elements of the test described in the draft is sufficient.
No
CenterPoint Energy appreciates the revisions made to Attachment 1 based on stakeholder feedback; however, the Company continues to have concerns regarding certain events and thresholds for reporting and offers the following recommendations. (1) CenterPoint Energy recommends the deletion of "per Requirement R1" in the “Note” under Attachment 1 as it contains a circular reference back to R1 which includes timeframes. (2) CenterPoint Energy maintains that a required 1 hour threshold for reporting of any event is unreasonable. CenterPoint Energy is confident that given dire circumstances Responsible Entities will act quickly on responding to and communication of any impending threat to the reliability of the Bulk Electric System. (3) For the event of “Damage or destruction of a Facility”, CenterPoint Energy is concerned that the use of the term “suspected” is too broad and proposes that the SDT delete "suspected" and add "that causes an Adverse Reliability Impact…" to the threshold for reporting regarding human action. (4) CenterPoint Energy believes that the event, “Any physical threat that could impact the operability of a Facility” is too broad and should be deleted. Alternatively, CenterPoint Energy recommends that the SDT delete "could” or change the event description to "A physical incident that causes an Adverse Reliability Impact". Additionally, in footnote 1, the example of a train derailment uses the phrase “could have damaged”. CenterPoint Energy is concerned that as beauty is the eye of the beholder, this phrase is open to interpretation and therefore recommends that the phrase, “causes an Adverse Reliability Impact” be incorporated into the description. (5) The Company proposes that the threshold for reporting the event, “BES Emergency requiring manual firm load shedding” is too low. It appears the SDT was attempting to align this threshold with the DOE reporting requirement. However, as the SDT stated above, there are several valid reasons why this should not be done;therefore, CenterPoint Energy recommends the threshold be revised to “Manual

firm load shedding ≥ 300 MW”. (6) CenterPoint Energy also recommends a similar revision to the threshold for reporting associated with the “BES Emergency resulting in automatic firm load shedding” event. (“Firm load shedding ≥ 300 MW (via automatic under voltage or under frequency load shedding schemes, or SPS/RAS”) (7) CenterPoint Energy is uncertain of the event, “Loss of firm load for ≥ 15 minutes” and its fit with BES Emergency requiring manual firm load shedding or BES Emergency resulting in automatic firm load shedding. The Company believes that this event is already covered with manual firm load shedding and automatic firm load shedding and should therefore be deleted. (8) For the event of “System separation (islanding)”, CenterPoint Energy believes that 100 MW is inconsequential and proposes 300 MW instead. (9) For “Generation loss”, CenterPoint Energy suggests that the SDT add "only if multiple units” to the criteria of “1,000 MW for entities in the ERCOT or Quebec Interconnection”. (10) Finally, CenterPoint Energy recommends that the SDT delete the term “partial” under the “Entity with Reporting Responsibility” for “Complete or partial loss of monitoring capability”. The Company proposes revising the event description to "Loss of monitoring capability for > 30 minutes that causes system analysis tools to be inoperable”.
No
CenterPoint Energy does not agree with the SDT’s proposed section 812. The proposal for NERC to establish a system that will “…forward the report to the appropriate NERC departments, applicable regional entities, other designated registered entities, and to appropriate governmental, law enforcement, regulatory agencies as necessary. This can include state, federal, and provincial organizations.” is redundant with the draft Standard. Responsible entities are already required to report applicable events to NERC, applicable regional entities, registered entities, and appropriate governmental, law enforcement, and regulatory agencies. CenterPoint Energy believes if the SDT’s intent is to require NERC to distribute these system event reports, then EOP-004-2 should be revised to require responsible entities to only report the event to NERC. As far as distribution to appropriate NERC departments, CenterPoint Energy believes that is an internal NERC matter and does not need to be included in the Rules of Procedure.
CenterPoint Energy proposes that the purpose be enhanced to reflect risk and response. For example, the purpose could read “To sustain and improve reliability of the Bulk Electric System by identifying common risks reported by Responsible Entities as a source of lessons learned.” In the Background section under Law Enforcement Reporting, “the” should be added in front of “Bulk Electric System”. Also under the Background section - “Present expectations of the industry under CIP-001-1a”, CenterPoint Energy is not aware of any current annual requirements for CIP-001 and suggests that this section be revised to reflect that fact. CenterPoint Energy strongly believes that the Violation Severity Levels (VSL) should not be high or severe unless an Adverse Reliability Impact occurred. CenterPoint Energy is requesting that Requirement R2 be deleted and the phrase, "as a result of not implementing the plan/insufficient or untimely report, an Adverse Reliability Impact occurred” be added to the Requirement R1 VSL. Regarding the VSL for Requirement R4, the Violation Risk Factor should be "Lower" and read “the entity did not perform the annual test of the operating plan” as annual is to be defined by the entity or according to the CAN-0010.
Individual
Kirit Shah
Ameren
Yes
No
We appreciate the efforts of the DSR SDT and believe this latest Draft is greatly improved over the previous version. However, we propose the following suggestions: (1) The first Event category in Attachment 1 under 24 Hour Reporting is Applicable to GO and GOP entities. Yet the first 2 of 3 Thresholds for Reporting require data that is unobtainable for GO and GOP entities. Specifically, Events that “Affects an IROL (per FAC-014)” and “Results in the need for actions to avoid an Adverse Reliability Impact”. We believe these thresholds, and the use of the NERC Glossary term Adverse Reliability Impact, clearly show the SDT’s intent to limit reporting only to Events that have a major and significant reliability impact on the BES. GO or GOP does not have access to the wide-area view of the transmission system, making them to make this determination is impossible. As a result, we do not believe GO and GOP entities should have Reporting Responsibility for these types of Events. (2) For GO and GOP entities, the third Threshold is confusing as to which facilities in the plant it would be

applicable to; because the definition of "Facility" does not provide a clear guidance in that respect. For example, would a damage to ID fan qualify as a reportable event? (3) The second Event category in Attachment 1 under 24 Hour Reporting, "Any physical threat that could impact the operability of a Facility" is wide open to interpretation and thus impracticable to comply with. For example, a simple car accident that threatens any transmission circuit, whether it impacts the BES (as listed in the Threshold for the previous event in the table or any other measure) or not, is reportable. This list could become endless without the events having any substantial impact on the system. To continue this point, the Footnote 1 can also include, among many other examples, the following: (a) A wild fire near a generating plant, (b) Low river levels that might shut down a generating plant, (c) A crane that has partially collapsed near a generator switchyard, (d) Damage to a rail line into a coal plant, and/or (v) low gas pressure that might limit or stop operation of a natural gas generating plant. (4) The category, "Transmission Loss" is a concern also. If the meaning of Transmission Facility is included in the meaning of Facility as described in the event list, it may be acceptable; but, we still have a question how would a loss of a bus and the multiple radial element that may be connected to that bus would be treated? Also, how would a breaker failure affect this type of an event? The loss of a circuit is “intentional” (as opposed to Unintentional as listed in the threshold) for the failure of breaker, how will it be treated in counting three or more? We suggest a clarification for such types of scenarios. (5) Requirement R1.: 1.1 includes an exception from compliance with this Standard if there is a Cyber Security Incident according to CIP-008-3. However, note that the CIP-008-3 may not apply to all GO and GOP facilities. While the exception is warranted to eliminate duplicative event reporting plans, the language of this requirement is confusing as it does not clearly provides that message. (6) The second paragraph in Section C.1.1.2. Includes the phrases “…shall retain the current, document…” and “…the “date change page” from each version…” Is the “document” intended to be the Operating Plan? We do not see a defining reference in the text around this phrase; also, is a “date change page” mandatory for compliance with this Standard? We request additional clarification of wording in the Evidence Retention section of the Standard. (7) Page 19 / Event: Voltage deviation on a Facility: We believe that the term “observes” for Entity with Reporting Responsibility be changed back to “experiences” as originally written. The burden should rest with the initiating entity in consistency with other Reporting Responsibilities. In addition, for Threshold for Reporting, We believe the language should be expanded to - plus or minus 10%”of nominal voltage” for greater than or equal to 15 continuous minutes. (8) Page 20 /Event: Complete or partial loss of monitoring capability. We suggest to the SDT that the term “partial” be deleted from the event description. (9) We suggest to the SDT that the term “partial” be deleted for the Entity with Reporting Responsibility and changed to read: Each RC, BA, and TOP that experiences the complete loss of monitoring capability.
No
If the SDT keeps new Section 812 we suggest to the SDT a wording change for the second sentence, underlined: “Upon receipt of the submitted report, the system shall then forward the report to the appropriate NERC department for review. After review, the report will be forwarded to the applicable regional entities, other designated registered entities, and to appropriate governmental, law enforcement, regulatory agencies as necessary.”
Individual
Howard Rulf
We Energies
Yes
No
Submitting reports to the ERO: NERC and all of the Regional Entities are the ERO. If I send a report to any Regional Entity (and not NERC), I have sent it to the ERO. Damage or Distruction of a Facility: A DP may not have a Facility by the NERC Glossary definition. All distribution is not a Facility. Did you mean to exclude all distribution? Any Physical threat that could impact the operability of a Facility: An RC does not have Facilities by the NERC Glossary definition. An RC will not have to report this. BES Emergency... Reporting Responsibility: If meeting the Reporting Threshold was due to a directive from the RC, who is the Initiating entity? Voltage deviation on a Facility Threshold for Reporting: 10% of what voltage? Nominal, rated, scheduled, design, actual at an instant?
No

Section 812 refers to the section as a standard and as a Procedure. That is not correct. Section 812 reads to me as if NERC (the system) will be forwarding everything specified anywhere in RoP 800.
Applicability: Change Electric Reliability Organisation to NERC or delete Regional Entity. The ERO is NERC and all the Regional Entities. R1.2: The ERO is NERC and all the REs. If I report to any one on the REs (only and not to NERC), I have reported to the ERO. Change ERO to NERC. M1 refers to R1.1 and R1.2 as Parts. It would be clearer to refer to them as requirements or sub-requirements. M2: Add a comma after "that the event was reported" and "supplemented by operator logs". It will be easier to read. R3: This should be clarified to state that no reporting will be done for the annual test, not just exclude the ERO. M4: An annual review will not be time stamped.
Group
SMUD & BANC
Joe Tarantino
We feel issues were addressed, but still have concern with ‘damage’. We certainly support that any ‘destruction’ of a facility that meets any of the three criteria be a reportable issue. But ‘damage’, if it’s going to be included should have some objective definition that sets a floor. Much like the copper theft issue, we don’t see the benefit of reporting plain vandalism (gun-shot insulators results from actual or suspected intentional human action) to NERC unless the ‘damage’ has some tangible impact on the reliability of the system or are acts of an orchestrated sabotage (i.e. removal of bolt in a transmission structure).
Individual
Brian J Murphy
NextEra Energy Inc
No
NextEra Energy, Inc. (NextEra) does not agree that annual reviews and annual tests should be mandated via Reliability Standards; instead, NextEra believes it is more appropriate to require that the Operating Plan be up-to-date and reviewed/tested as the Responsible Entity deems necessary. These enhancements provide for a robust Operating Plan, without arbitrary deadlines for a review and testing. It also provides Responsible Entities of different sizes and configurations the flexibility to efficiently and effectively integrate compliance with operations. Thus, NextEra requests that R1 be revised to read: “Each Responsible Entity shall have an up-to-date event reporting Operating Plan that is tested and reviewed as the Responsible Entity deems necessary and includes: …”. Consistent with these changes NextEra also requests that R3 and R4 be deleted.
No
As stated in NextEra’s past comments, we continue to be concerned that EOP-004-2 does not appropriately address actual sabotage that threatens the Bulk Electric System (BES) versus random acts that are isolated and pose no risk to the BES. Therefore, NextEra repeats a portion of its past comments below in the hope that the next revision of EOP-004-2 will more adequately address NextEra’s concerns. Specifically, NextEra’s requests that its definition of sabotage set forth below replace Attachment 1’s “Damage and Destruction of Equipment” and “Any physical threat that could impact the operability of a Facility.” In Order No. 693, FERC stated its interest in NERC revising CIP-001 to better define sabotage and requiring notification to the certain appropriate federal authorities, such as the Department of Homeland Security. FERC Order No. 693 at PP 461, 462, 467, 468, 471. NextEra has provided an approach that accomplishes FERC’s objectives and remains within the framework of the drafting team, but also focuses the process of determining and reporting on only those sabotage acts that could affect other BES systems. Today, there are too many events that are being reported as sabotage to all parties in the Interconnection, when in reality these acts have no material affect or potential impact to other BES systems other than the one that experienced it. For example, while the drafting team notes the issue of copper theft is a localized act, there are other localized acts of sabotage that are committed by an individual, and these acts pose little, if any, impact or threat to other BES systems. Reporting sabotage that does not need to be sent to everyone does not add to the security or reliability of the BES. Relatedly, there is a need to clarify some of the current industry confusion on who should (and has the capabilities to) be reporting to a broader

audience of entities. Hence, the NextEra approach provides a clear definition of sabotage, as well as the process for determining and reporting sabotage. New Definition for Sabotage. Attempted or Actual Sabotage: an intentional act that attempts to or does destroy or damage BES equipment for the purpose of disrupting the operations of BES equipment, or the BES, and has a potential to materially threaten or impact the reliability of one or more BES systems (i.e., one act of sabotage on BES equipment is only reportable if it is determined to be part of a larger conspiracy to threaten the reliability of the Interconnection or more than one BES system).
Given that Responsible Entities are already required by other Reliability Standards to communicate threats to reliability to their Reliability Coordinator (RC), NextEra does not believe that EOP-004-2 is a Reliability Standard that promotes the reliability of the bulk power system, as envisioned by Section 215 of the Federal Power Act. Because an RC reporting requirement is already covered in other Standards, EOP-004-2 essentially is a reporting out requirement to the Regional Reliability Organization (RRO). NextEra does not agree that the reporting of events to the RROs should be subject to fines under the Reliability Standard regulatory framework. The reporting to RROs, as required by EOP-004-2, while informative and helpful for lessons learned, etc., is not necessary to address an immediate threat to reliability. In addition, NextEra does not believe it would be constructive to fine Responsible Entities for failure to report to a RRO within a mandated deadline during times when these entities are attempting to address potential sabotage on their system. NextEra would, therefore, prefer that the EOP-004-2 Standards Drafting Team be disbanded, and instead that EOP-004-2's reporting requirements be folded in to the event analysis reporting requirements. Therefore, NextEra requests that the new Section 812 be revised to include EOP-004-2 as a data request for lessons learn or for informational purposes only, and, also, for EOP-004-2 project to be disbanded.
Individual
Kathleen Goodman
ISO New England Inc
No
Due to the FERC mandate to assign VRFs/VSLs, we do not support using subrequirements and, instead, favor the use of bullets when the subrequirements are not standalone but rely on the partent requirement.
No
We unable to comment on the proposed new section as the section does not contain any description of the proposed process or the interface requirements to support the report collecting system. We reserve judgment on this proposal and our right to comment on the proposal when the proposed addition is posted.
We requests that the SDT post the following Alternative Proposal for Industry comments as required by the Standards Process to obtain Industry consensus and as permitted by FERC: An equally effective alternative is to withdraw this standard and to make the contents of the SDT's posted standard a NERC Guideline. a. This alternative is more in line with new NERC and FERC proposals b. This alternative retains the reporting format Comments 1. The FERC Order 693 directives regarding "sabotage" have already been addressed by the SDT (i.e. the concept was found outside the scope of NERC standards) 2. Current Industry actions already address the needs cited in the Order: a. Approved Reporting Processes already exists i. The Operating Committee's Event Analysis Process ii. Alert Reporting b. The Data already exists i. Reliability Coordinators Information System (which creates hundred if not thousands of "reports" per year) ii. The DOE's OE 417 Report itself provides part of the FERC discussed data 3. The proposed standard is not supportive of Gerry Cauley's performance based standard initiative or of FERC's offer to reduce procedural standards a. The proposed requirement is a process not an outcome i. The proposal is more focused on reporting and could divert the attention of reliability entities from addressing a situation to collecting data for a report b. The proposed "events" are subjective and if followed will create an unmanageable burden on NERC staff i. Reporting "damage" to facilities can be interpreted as anything from a dent in a generator to the total destruction of a transformer ii. The reporting requirements on all applicable entities will create more questions about differences between the reports of the various entities – rather than leading to conclusions about patterns among events that indicate a global threat iii.

Reporting any “physical threat” is too vague and subjective iv. Reporting “damage to a facility that affects an IROL” is subjective and can be seen to require reporting of damage on every facility in an interconnected area. v. Reporting “Partial loss of monitoring” is a data quality issue that can be anything from the loss of a single data point to the loss of an entire SCADA system vi. Testing the filling out of a Report does not make it easier to fill out the report later (moreover the reporting is already done often enough –see 2.b.i) c. The proposed requirements will create a disincentive to improving current Reporting practices (the more an entity designs into its own system the more it will be expected to do and the more likely it will be penalized for failing to comply) i. Annual reviews of the reporting practices fall into the same category, why have a detailed process to review when a simple one will suffice? 4. The proposed standard does not provide a feedback loop to either the data suppliers or to potentially impacted functional entities a. If the “wide area” data analysis indicates a threat, there is no requirement to inform the impacted entities b. As a BES reliability issue there is no performance indicators or metrics to show the value of this standard i. We recognize that specific incidents cannot be identified but if this is to be a reliability standard some information must be provided. A Guideline could be designed to address this concern. 5. The proposed standard is not consistent with NERC’s new Risk Based Compliance Monitoring. a. The performance based action to report on defined events, as required in R2, could be considered a valid requirement. However we have concerns as noted in Bullet 3 above. The requirements laid out in R1, R3 and R4 are specific controls to ensure that the proposed requirement to report (R2) is carried out. NERC is moving in the direction to assess entities’ controls, outside of the compliance enforcement arm. The industry is being informed that NERC Audit staff will conduct compliance audits based on the controls that the entity has implemented to ensure compliance. We are interested in supporting this effort and making it successful. However, if this is the direction NERC is moving, we should not be making controls part of a compliance requirement. The only requirement proposed in this standard that is not a control is R2. 6. For FERC-jurisdictional entities, NERC does not need to duplicate the enforcement of reporting already imposed by the DOE. DOE-417 is a well established process that has regulatory obligations. NERC enforcement of reporting would be redundant. NERC has the ability to request copies of these reports without making them part of the Reliability Rules.
Group
ISO/RTO Standards Review Committee
Albert DiCaprio
No
The SRC offers comments regarding the posted draft requirements; however, by so doing, the SRC does not indicate support of the proposed requirements. Following these comments, please see the latter part of the SRC’s response to Question 4 below for an SRC proposed alternative approach: Regarding the proposed posted requirements, without indicating support of those requirements, the SRC concurs with the changes as they provide better streamlining of the four key requirements, with enhanced clarity. However, we are unclear on the intent of Requirement R3, in particular the phrase “not including notification to the Electric Reliability Organization” which begs the question on whether or not the test requires notifying all the other entities as if it were a real event. This may create confusion in ensuring compliance and during audits. Suggest the SDT to review and modify this requirement as appropriate. Regarding part 1.2, the SRC requests that the text be terminated after the word “type” and before “i.e.” As written, the requirement does not allow for the entity to add/remove others as necessary. Please consider combining R3 and R4. These can be accomplished at the same time. The process should be evaluated to determine effectiveness when an exercise or test is conducted. The SDT is asked to review the proposal and to address the issue of requirements vs. bullets vs. sub-requirements. It is suggested that each requirement be listed independently, and that each sub-step be bulleted.
No
The SRC response to this question does not indicate support of the proposed requirement. Please see the latter part of the SRC’s response to Question 4 below for an SRC proposed alternative approach:
No
The SRC offers comments regarding the posted draft requirements; however, by so doing, the SRC does not indicate support of the proposed requirements. Following these comments, please see the latter part of the SRC’s response to Question 4 below for an SRC proposed alternative approach: The SRC is unable to comment on the proposed new section as the section does not contain any

description of the proposed process or the interface requirements to support the report collecting system. We reserve judgment on this proposal and our right to comment on the proposal when the proposed addition is posted.
The SRC offers some other comments regarding the posted draft requirements; however, by so doing, the SRC does not indicate support of the proposed requirements. Following these comments, please see below for an SRC proposed alternative approach: The SRC does not agree with the MEDIUM VRF assigned to Requirement R4. R4 is a requirement to conduct an annual review of the Event Reporting Operating Plan mandated in Requirement R1. R1 however is assigned a VRF of LOWER. We are unable to rationalize why a subsequent review of a plan should have a higher reliability risk impact than the development of the plan itself. Hypothetically, if an entity doesn't develop a plan to begin with, then it will be assigned a LOWER VRF, and the entity will have no plan to review annually and hence it will not be deemed non-compliant with requirement R4. The entity can avoid being assessed violating a requirement with a MEDIUM VRF by not having the plan to begin with, for which the entity will be assessed violating a requirement with a LOWER VRF. We suggest changing the R4 VRF to LOWER. ** The SRC requests that the SDT post the following Alternative Proposal for Industry comments as required by the Standards Process to obtain Industry consensus and as permitted by FERC: An equally effective alternative is to withdraw this standard and to make the contents of the SDT's posted standard a NERC Guideline. a. This alternative is more in line with new NERC and FERC proposals b. This alternative retains the reporting format Comments 1. The FERC Order 693 directives regarding "sabotage" have already been addressed by the SDT (i.e. the concept was found outside the scope of NERC standards) 2. Current Industry actions already address the needs cited in the Order: a. Approved Reporting Processes already exists i. The Operating Committee's Event Analysis Process ii. Alert Reporting b. The Data already exists i. Reliability Coordinators Information System (which creates hundred if not thousands of "reports" per year) ii. The DOE's OE 417 Report itself provides part of the FERC discussed data 3. The proposed standard is not supportive of Gerry Cauley's performance based standard initiative or of FERC's offer to reduce procedural standards a. The proposed requirement is a process not an outcome i. The proposal is more focused on reporting and could divert the attention of reliability entities from addressing a situation to collecting data for a report b. The proposed "events" are subjective and if followed will create an unmanageable burden on NERC staff i. Reporting "damage" to facilities can be interpreted as anything from a dent in a generator to the total destruction of a transformer ii. The reporting requirements on all applicable entities will create more questions about differences between the reports of the various entities – rather than leading to conclusions about patterns among events that indicate a global threat iii. Reporting any "physical threat" is too vague and subjective iv. Reporting "damage to a facility that affects an IROL" is subjective and can be seen to require reporting of damage on every facility in an interconnected area. v. Reporting "Partial loss of monitoring" is a data quality issue that can be anything from the loss of a single data point to the loss of an entire SCADA system vi. Testing the filling out of a Report does not make it easier to fill out the report later (moreover the reporting is already done often enough –see 2.b.i) c. The proposed requirements will create a disincentive to improving current Reporting practices (the more an entity designs into its own system the more it will be expected to do and the more likely it will be penalized for failing to comply) i. Annual reviews of the reporting practices fall into the same category, why have a detailed process to review when a simple one will suffice? 4. The proposed standard does not provide a feedback loop to either the data suppliers or to potentially impacted functional entities a. If the "wide area" data analysis indicates a threat, there is no requirement to inform the impacted entities b. As a BES reliability issue there is no performance indicators or metrics to show the value of this standard i. The SRC recognizes that specific incidents cannot be identified but if this is to be a reliability standard some information must be provided. A Guideline could be designed to address this concern. 5. The proposed standard is not consistent with NERC's new Risk Based Compliance Monitoring. a. The performance based action to report on defined events, as required in R2, could be considered a valid requirement. However we have concerns as noted in Bullet 3 above. The requirements laid out in R1, R3 and R4 are specific controls to ensure that the proposed requirement to report (R2) is carried out. NERC is moving in the direction to assess entities' controls, outside of the compliance enforcement arm. The industry is being informed that NERC Audit staff will conduct compliance audits based on the controls that the entity has implemented to ensure compliance. The SRC is interested in supporting this effort and making it successful. However, if this is the direction NERC is moving, we should not be making controls part of a compliance requirement. The only requirement proposed in this standard that is not a control is R2. 6. For FERC-jurisdictional

entities, NERC does not need to duplicate the enforcement of reporting already imposed by the DOE. DOE-417 is a well established process that has regulatory obligations. NERC enforcement of reporting would be redundant. NERC has the ability to request copies of these reports without making them part of the Reliability Rules.
Individual
Mark B Thompson
Alberta Electric System Operator
The Alberta Electric System Operator will need to modify parts of this standard to fit the provincial model and current legislation when it develops the Alberta Reliability Standard.
Individual
Maggy Powell
Exelon Corporation and its affiliates
No
It’s not clear that R3 and R4 need to be separated. Consider revising R3 to read: “Through use or testing, verify the operability of the plan on an annual basis” and dropping R4.
Yes
No
While we don’t have any immediate objection to revising the Rules of Procedures (ROP) to allow for report collecting under Section 800 relative to the EOP-004 standard, the proposed language is unclear and confusing. Please consider the following revision: "812. NERC Reporting Clearinghouse NERC will establish a system to collect reporting forms as required for Section 800 or per FERC approved standards from any Registered Entities. NERC shall distribute the reports to the appropriate governmental, law enforcement, regulatory agencies as required per Section 800 or the applicable standard." Further, NERC should post ROP revisions along with a discussion justifying the revision for industry comment specific to the ROP. There may be significant implications to this revision beyond the efforts relative to EOP-004.
Thanks to the SDT. Significant progress was made in revising the proposed standard language. We appreciate the effort and have only a few remaining requests: • We understand that CIP-008 dictates the 1-hour reporting obligation for Cyber Security Incidents and this iteration of EOP-004 delineates the CIP-008 requirements. Please confirm that per the exemption language in the CIP standards (as consistent with the March 10, 2011 FERC Order (docket # RM06-22-014) nuclear generating units are not subject to this reporting requirement. • EOP-004 still lists “Generation Loss” as a 24 hour reporting criteria without any time threshold guidance for the generation loss. Exelon previously commented to the SDT (without the comment being addressed) that Generation Loss should provide some type of time threshold. If the 2000 MW is from a combination of units in a single location, what is the time threshold for the combined unit loss? In considering clarification language, the SDT should review the BAL standards on the disturbance recovery period for appropriate timing for closeness of trips. • The “physical threat that could impact” requirement remains vague and it’s not clear the relevance of such information to NERC or the Regions. If a train derailment occurred near a generation facility (as stated in the footnote), are we to expect that NERC is going to send out a lesson learned with suggested corrective actions to protect generators from that occurring? The value in that event reporting criteria seems low. The requirement should be removed. • The event concerning voltage deviation of +/- 10% does not specify which type of voltage. In response to this comment in the previous comment period, the SDT indicated that the entity could determine the type of voltage. It would be clearer to specify in the standard and avoid future interpretation at the audit level. • As requested previously, for nuclear facilities, EOP-004 reporting should be coordinated with existing required notifications to the NRC and FBI as to not duplicate effort or add unnecessary burden on the part of a nuclear GO/GOP during a potential security or cyber event. Please contact the NRC about this project to ensure that required communication and reporting in response to a radiological sabotage event (as defined by the NRC) or any incident that has impacted or has the

potential to impact the BES does not create duplicate reporting, conflicting reporting thresholds or confusion on the part of the nuclear generator operator. Each nuclear generating site licensee must have an NRC approved Security Plan that outlines applicable notifications to the FBI. Depending on the severity of the security event, the nuclear licensee may initiate the Emergency Plan (E-Plan). Exelon again asks that the proposed reporting process and flow chart be coordinated with the NRC to ensure it does not conflict with existing expected NRC requirements and protocol associated with site specific Emergency and Security Plans. In the alternative, the EOP-004 language should include acceptance of NRC required reporting to meet the EOP-004 requirements. • The proposed standard notes that the text boxes will be moved to the Guideline and Technical Basis Section which we support. However, it's not clear whether all the information in the background section will remain part of the standard. If this section is to remain as proposed concerted revision is needed to ensure that the discussion language matches the requirement language. At present, it does not. For instance, the flow chart on page 9 indicates when to report to law enforcement while the requirements merely state that communications to law enforcement be addressed within the operating plan. • Exelon voted negative vote on this ballot due to the need for further clarification and reconciliation between NERC EOP-004 and the NRC.
Individual
Keith Morisette
Tacoma Power
Yes
Tacoma Power agrees with the requirement but would suggest removing all instances the word "Operating" from the Standard. The requirements should read, " Each Responsible Entity shall have an "Event Reporting Plan…". The term Operating in this context is confusing as there are many other "Operating Plans" for other defined emergencies. This standard is about "Reporting" and should be confined to that.
Yes
Tacoma Power supports the revisions. It appears that all agencies and entities are willing to support the use of the DOE Form OE-417 as the initial notification form (although EOP-004 does include their own reporting form as an attachment to the Standard). Tacoma is already using the OE-417 and distributing it to all applicable Entities and Agencies.
No
Tacoma Power disagrees with the requirement to perform annual testing of each communication plan. We do not see any added value in performing annual testing of each communication plan. There are already other Standard requirements to performing routine testing of communications equipment and emergency communications with other agencies. The "proof of compliance" to the Standard should be in the documentation of the reports filed for any qualifying event, within the specified timelines and logs or phone records that it was communicated per each specified communication plan.
Tacoma Power disagrees with the requirement to perform annual testing of each communication plan. We do not see any added value in performing annual testing of each communication plan. There are already other Standard requirements to performing routine testing of communications equipment and emergency communications with other agencies. The "proof of compliance" to the Standard should be in the documentation of the reports filed for any qualifying event, within the specified timelines and logs or phone records that it was communicated per each specified communication plan. Tacoma Power has none at this time. Thank you for considering our comments.
Individual
Dennis Sismaet
Seattle City Light
Yes
This is a great improvement over the prior CIP and EOP versions. However, please see #4 for overall comment.
Yes
This is a great improvement over the prior CIP and EOP versions. However, please see #4 for overall comment.
No

Seattle City Light follows MEAG and believes this type of activity and process is better suited to NAESBE than it is to NERC Compliance.
1) Seattle City Light follows MEAG and questions if these administrative activities better should be sent over to NAESB? R1: There is merit in having a plan as identified in R1, but is this a need to support reliability or is it a business practice? Should it be in NAESB's domain? R2, R3 & R4: These are not appropriate for a Standard. If you don't annually review the plan, will reliability be reduced and the BES be subject to instability, separation and cascading? If DOE needs a form filled out, fill it out and send it to DOE. NERC doesn't need to pile on. Mike Moon and Jim Merlo have been stressing results and risk based, actual performance based, event analysis, lessons learned and situational awareness. EOP-004 is primarily a business preparedness topic and identifies administrative procedures that belong in the NAESB domain. 2) Seattle City Light finds that even though efforts were made to differentiate between sabotage vs. criminal damage, the difference still appears to be confusing. Sabotage clearly requires FBI notification, but criminal damage (i.e. copper theft, trespassing, equipment theft) is best handled by local law agencies. A key point on how to determine the difference is to always go with the evidence. If you have a hole in the fence and cut grounding wires, this would only require local law enforcement notification. If there is a deliberate attack on a utility's BES infrastructure for intent of sabotage and or terrorism--this is a FBI notification event. One area where a potential for confusion arises is with the term "intentional human action" in defining damage. Shooting insulators on a rural transmission tower is not generally sabotage, but removing bolts from the tower may well be. Seattle understands the difficulty in differentiating these two cases, for example, and supports the proposed Standard, but would encourage additional clarification in this one area.
Individual
Scott Miller
MEAG Power
Yes
This is a great improvement over the prior CIP and EOP versions. However, please see #4 for overall comment.
Yes
This is a great improvement over the prior CIP and EOP versions. However, please see #4 for overall comment.
No
This type of activity and process is better suited to NAESBE than it is to NERC Compliance.
Should these administrative activities be sent over to NAESB? R1: There is merit in having a plan as identified in R1, but is this a need to support reliability or is it a business practice? Should it be in NAESB's domain? R2, R3 & R4: These are not appropriate for a Standard. If you don't annually review the plan, will reliability be reduced and the BES be subject to instability, separation and cascading? If DOE needs a form filled out, fill it out and send it to DOE. NERC doesn't need to pile on. Mike Moon and Jim Merlo have been stressing results and risk based, actual performance based, event analysis, lessons learned and situational awareness. EOP-004 is primarily a business preparedness topic and identifies administrative procedures that belong in the NAESB domain.
Group
FirstEnergy
Sam Ciccone
While FE voted affirmative on this draft, upon further review we request clarification be made in the next draft of the standard regarding the applicability of the Nuclear Generator Operator. Per FE's previous comments, nuclear generator operators already have specific regulatory requirements to notify the NRC for certain notifications to other governmental agencies in accordance with 10 CFR 50.72(b)(s)(xi). We had asked that the DSR SDT contact the NRC about this project to ensure that existing communication and reporting that a licensee is required to perform in response to a radiological sabotage event (as defined by the NRC) or any incident that has impacted or has the

potential to impact the BES does not create either duplicate reporting, conflicting reporting thresholds or confusion on the part of the nuclear generator operator. In addition, EOP-004 must acknowledge that there may be NRC reporting forms that have the equivalent information contained in their Attachment 2. For what the NRC considers a Reportable Event, Nuclear plants are required to fill out NRC form 361 and/or form 366. We do not agree with the drafting team's response to ours and Exelon's comments that "The NRC does not fall under the jurisdiction of NERC and so therefore it is not within scope of this project." While the statement is correct, we believe that requirements should not conflict with or duplicate other regulatory requirements. We remain concerned that the standard with regard to Nuclear GOP applicability causes duplicative regulatory reporting with existing reporting requirements of the NRC. Therefore, we ask: 1. That NERC and the drafting team please investigate these issues further and revise the standard to clarify the scope for nuclear GOPs, and 2. For any reporting deemed in the scope for nuclear GOP after NERC's and the SDT's investigation per our request in #1 above, that the SDT consider the ability to utilize information from NRC reports as meeting the EOP-004-2 requirements similar to the allowance of using the DOE form as presently proposed.
Individual
Patrick Brown
Essential Power, LLC
1. As this Standard does not deal with real-time reporting or analysis, and is simply considered an after the fact reporting process, I question the need for the Standard at all. This is a process that could be handled through a change to the Rules of Procedure rather than through a Standard. Developing this process as a Reliability Standard is, in my opinion, contrary to the shift toward Reliability-Based Standards Development. 2. I do not believe that establishing a reporting requirement improves the reliability of the BES, as stated in the purpose statement. The reporting requirement, however, would improve situational awareness. I recommend the purpose statement be changed to reflect this, and included with the process in the NERC Rules of Procedure.
Individual
Gregory Campoli
New York Independent System Operator
The NYISO is part of and supports comments submitted by NPCC Reliability Standards Committee and the IRC Strandards Review Committee. However the NYISO would also like to comment on the following items: o NERC has been proposing the future development of performance based standards, which is directly related to reliability performance. Requirement 2 of this standard is simply a reporting requirement. We believe that this does not fall into a category of a performance based standard. NERC has the ability to ask for reports on events through ROP provisions and now the new Event Analysis Process. It does not have to make it part of the compliance program. Some have indicated that need for timely reporting of cyber or sabotage events. The counter argument is that the requirement is reporting when confirmed which would delay any useful information to fend off a simultaneous threat. Also NERC has not provided any records of how previous timely (1 hour) reporting has mitigated reliability risks. o The NERC Event Analysis Process was recently approved by the NERC OC and is in place. This was the model program for reporting outside the compliance program that the industry was asking for. This should replace the need for EOP-004. o NERC has presented Risk Based Compliance Monitoring (RBCM) to the CCC, MRC, BOT and at Workshops. This involves audit teams monitoring an entities controls to ensure they have things in place to maintain compliance with reliability rules. The proposed EOP-004 has created requirements that are controls to requirement R2, which is to file a report on predefined incidents. The RBCM is being presented as the auditor will make determinations on the detail of the sampling for compliance based on the assessment of controls an entity has in place to maintain compliance. It is also noted that compliance will not be assessed against these controls. As the APS example for COM-002 is presented in the

Workshop slides, the issue is that EOP-004 R1, R3 and R4 are controls for reporting; 1) have a plan, 2) test the plan, and 3) review the plan. While R2 is the only actionable requirement. The NYISO believes that all reporting requirements have been met by OE-417 and EAP reporting requirements and that EOP-004 has served its time. At a minimum, the NYISO would suggest that EOP-004 be simplified to just R2 (reporting requirement) and the other requirements be placed at the end of the RSAW to demonstrate a culture of compliane as presented by NERC.
Individual
Don Schmit
Nebraska Public Power District
No
1. The following comments are in regard to Attachment 1: A. The row [Event] titled “Damage or destruction of Facility”: 1. In column 3 [Threshold for Reporting], the word “Affect” is vague note the following concerns: i. Does “Affect” include a broken crossarm damaged without the Facility relaying out of service. This could be considered to have an “Affect” on the IROL. ii. Would the answer be different if the line relayed out of service and auto-reclosed (short interuption) for the same damaged crossarm? We need clarity from the SDT in order to know when a report is due. 2. For clarification: Who initiates the report when the IROL interfaces spans between multiple entities? We know of an IROL that has no less that four entities that oparate Facilities within the interface. Who initiates the report of the IROL is affected? All? B. The row [Event] titled “Any physical threat that could impact the operability of a Facility”: 1. In Column 1 [Event] change the word “threat” to “attack”, this aligns with the OE-417 report. 2. In Column 3 [Threshold for Reporting], align the threshold with the OE-417 form. C. The row [Event] titled “Transmission loss”, in column 3 [Threshold for Reporting], the defined term “Transmission Facilities” is too vague. There needs to be a more description such that an entity clearly understands when an event is reportable and for what equipment. We would recommend the definition used in the Event Reporting Field Trial: An unexpected outage, contrary to design, of three or more BES elements caused by a common disturbance. Excluding successful automatic reclosing. For example: a. The loss of a combination of NERC-defined Facilities. b. The loss of an entire generation station of three or more generators (aggregate generation of 500 MW to 1,999 MW); combined cycle units are represented as one unit. D. The row [Event] titled “Complete or partial loss of monitoring”: 1. In column 1 [Event], delete the words “or partial”. This is subjective without definition, delete. 2. Also in column 1 [Event], delete the word “monitoring” and replace with Supervisory Control and Data Acquisition (SCADA). SCADA is defined term that explicitly calls out in the definition “monitoring and control” and is understood by the industry as such. 3. In column 2 [Entity with Reporting Responsibility], delete the words “or partial”; also delete the word “monitoring” and replace with SCADA. 4. In column 3 [Threshold for Reporting], reword to state “Complete loss of SCADA affecting a BES control center for >/= 30 continuous minutes”.
Individual
David Revill
GTC
Yes
No
Page 17 & 18, One Hour Reporting and Twenty-four Hour Reporting: append the introductory statements with the following: “meeting the threshold for reporting” after recognition of the event. Example: Submit EOP-004 Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within twenty-four hours of recognition of the event meeting the threshold for reporting. Page 19, system separation (islanding); Clarify the intent of this threshold for reporting: Load >= 100 MW and any generation; or Load >= 100 MW and Generation >= 100 MW, or some combination of load and generation totaling 100 MW.
Yes
With the exception of the RC and company personnel, it appears this proposed section captures the

same reporting obligations and to the same entities via R1.2. Recommend adjustments to R1.2 such that reportable events are submitted to NERC, RC, and company personnel.
For R2, please clarify how an entity can demonstrate that no reportable events were experienced. GTC recommends an allowance for a letter of attestation within M2.
Individual
Scott Berry
Indiana Municipal Power Agency
No
IMPA does not believe that both R3 and R4 are necessary and they are redundant to a degree. Generally, when performing an annual review of a process or procedure, the call numbers for agencies or entities are verified to be up to date. Also, in R3, what does “test” mean. It could mean have different meanings to registered entities and to auditors which does not promote consistency among the industry. IMPA recommends going with an annual review of the process and having the telephone numbers verified that are in the event reporting Operating Plan. IMPA also believes that the local and federal law enforcement agencies would rather go with a verification of contact information over being besieged by "test" reports. The way R3 is written gives the appearance that the SDT did not want to overwhelm the ERO with all of the "test" reports from the registered entities (by excluding them from the test notification).
No
The event "any physical threat that could impact the operability of a Facility" is not measurable and can be interpreted many ways by entities or auditors. IMPA recommend incorporating language that let's this be the judgment of the registered entity only. On the "voltage deviation on a Facility", IMPA recommends that only the TOP the experiences a voltage deviation be the one responsible for reporting. For generation loss and transmission loss, IMPA believes that the amount of loss needs to be associated with a time period or event (concurrent forced outages).
no comment
For 1.2 under R1, is the SDT leaving it up to the registered entities do decide which organizations will be contacted for each event listed in attachment 1 or do all of those organization need to be contacted for each event listed in attachment 1? The requirement needs to clearly communicate this clarification and be independent of the rationale language. Auditors will go by the requirement and not the rationale for the requirement. For 1.1 under R1, does each event need its own process of recognition or can one process be used to cover all the applicable events? The requirement needs to clearly communicate this clarification and be independent of the rationale language. Auditors will go by the requirement and not the rationale for the requirement. For 1.2 under R1, company personnel is used as an example but in the rationale for R1, the third line uses operating personnel. IMPA recommends changing the example in 1.2 to operating personnel which is used in the current version of CIP-001.
Individual
Christine Hasha
ERCOT
No
ERCOT has joined the IRC comments on this project and offers these additional comments. ERCOT requests that the measure be updated to say “acceptable evidence may include”. As written, the measure reads that there is only one way to comply with the requirement. The Standards should note "what" an entity is required to do and not prescribe the "how".
Yes
No
ERCOT has joined the IRC comments on this project.
ERCOT has joined the IRC comments on this project and offers these additional comments. ERCOT supports the alternative approach submitted by the IRC. ERCOT requests that time horizons be added for each of the requirements as have been with other recent Reliability Standards projects. With regards to Attachment 1, ERCOT requests the following changes: • Modify “Generation loss” from “≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection” to “≥ 1,100 MW for entities in the

ERCOT Interconnection” and “≥ 1,000 MW for entities in the Quebec Interconnection”. This is consistent with the DCS threshold and eliminates possible operator confusion since DCSs event are reported in the ERCOT interconnection at 80% of single largest contingency which equates to 1100 MW. • Modify “Transmission loss” from “Unintentional loss of three or more Transmission Facilities (excluding successful automatic reclosing)” to “Inconsequential loss of three or more Transmission Facilities not part of a single rated transmission path (excluding successful automatic reclosing).” If a single line is comprised of 3 or more sections, this should not be part of what is reported here as it is intended to be when you have a single event trip of 3 or more transmission facilities that is not part of its intended design. • ERCOT requests review of footnote 1. The footnote does not seem appropriate in including an example of a control center as the definition of a BES facility does not include control centers.
Individual
Molly Devine
Idaho Power Co.
Yes
But this is going to require that we create a new Operating Plan with test procedures and revision history.
No
I think that the category “Damage or destruction of a Facility” is too ambiguous, and the Threshold for Reporting creteria does not help to clarify the question. Any loss of a facility may result in the need for actions to get to the new operating point, would this be a reportable disturbance?
No
No opinion
No
Individual
Rebecca Moore Darrah
MISO
Yes
No
No
MISO agrees with and adopts the Comments of the IRC on this issue.
Individual
Nathan Mitchell
American Public Power Association
Yes
APPA appreciates the SDT making these requirements clearer as requested in our comments on the previous draft standard.
No
APPA in our comments on the previous draft of EOP-004-2 requested relief for small entities from this reporting/documentation standard. APPA suggested setting a 300 MW threshold for some of the criteria in Attachment 1. This suggestion was not accepted by the SDT. However, the SDT is still directed by FERC to “consider whether separate, less burdensome requirements for smaller entities may be appropriate. Therefore, APPA requests that the SDT provide relief to small entities by providing separate requirements for small entities by requiring reporting only when one of the four criteria in DOE-OE-417 are met: 1. Actual physical attack, 2. Actual cyber attack, 3. Complete operational failure, or 4. Electrical System Separation. APPA recommends this information should be reported to the small entity’s BA as allowed in the DOE-OE-417 joint filling process.
Yes

The SDT needs to provide some relief for the small entities in regards to the VSL in the compliance section. APPA believes there should be no High or Severe VSLs for this standard. This is a reporting/documentation standard and does not affect BES reliability at all. It is APPA's opinion that this standard should be removed from the mandatory and enforceable NERC Reliability Standards and turned over to a working group within the NERC technical committees. Timely reporting of this outage data is already mandatory under Section 13(b) of the Federal Energy Administration Act of 1974. There are already civil and criminal penalties for violation of that Act. This standard is a duplicative mandatory reporting requirement with multiple monetary penalties for US registered entities. If this standard is approved, NERC must address this duplication in their filing with FERC. This duplicative reporting and the differences in requirements between DOE-OE-417 and NERC EOP-004-2 require an analysis by FERC of the small entity impact as required by the Regulatory Flexibility of Act of 1980
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
No
(1) We agree with removing Part 1.4 and we agree with a requirement to periodically review the event reporting Operating Plan. However we are not convinced the review of the Operating Plan needs to be conducted annually. The event reporting Operating Plan likely will not change frequently so a biannual review seems more appropriate. (2) We also do not believe that Requirement R3 is needed at all. Requirement R3 compels the responsible entity to test their Operating Plan annually. We do not see how testing an Operating Plan that is largely administrative in nature contributes to reliability. Given that the drafting team is obligated to address the FERC directive regarding periodic testing, we suggest the Operating Plan should be tested biannually. This would still meet the FERC directive requiring periodic testing.
No
The drafting team made a number of positive changes to Attachment 1. However, there are a few changes that have introduced new issues and there are a number of existing issues that have yet to be fully addressed. One of the existing issues is that the reporting requirements will result in duplicate reporting. Considering that one of the stated purposes is to eliminate redundancy, we do not see how the scope of the SAR can be considered to be met until all duplicate reporting is eliminated. More specifics on our concerns are provided in the following discussion. (1) In the "Damage or destruction of a Facility" event, the statement "Affects an IROL (per FAC-014)" in the "Threshold for Reporting" is ambiguous. What does it mean? If the loss of a Facility will have a 1 MW flow change on the Facilities to which the IROL applies, is this considered to have affected the IROL? We suggest a more direct statement that damage or destruction occurred on a Facility to which the IROL applies or to one of the Facilities that comprise an IROL contingency as identified in FAC-014-2 R5.1.3. Otherwise, there will continue to be ambiguity over what constitutes "affects". (2) In the "Damage or destruction of a Facility" event, the threshold regarding "intentional human action" is ambiguous and suffers from the same difficulties as defining sabotage. What constitutes intentional? How do we know something was intentional without a law enforcement investigation? This is the same issue that prevented the drafting team from defining sabotage. (3) In the "Damage or destruction of a Facility" and "Any physical threat that could impact the operability of a Facility" events, Distribution Provider should be removed. Per the Function Model, the Distribution Provider does not have any Facilities (line, generator, shunt compensator, transformer). The only Distribution Provider equipment that even resembles a Facility would be capacitors (i.e. shunt compensator) but they do not qualify because they are not Bulk Electric System Elements. (4) The "Any physical threat that could impact the operability of a Facility" event requires duplicate reporting. For example, if a large generating plant experiences such a threat, who should report the event? What if loss of the plant could cause capacity and energy shortages as well as transmission limits? The end result is that the RC, BA, TOP, GO and GOP could all end up submitting a report for the same event. For a given operating area, only one report should be required from one registered entity for each event. (5) The "Any physical threat that could impact the operability of a Facility" event should not apply to a single Facility but rather multiple Facilities which if lost would impact BES reliability. As written now, a train derailment near a single 138 kV transmission line or small generator with minimal reliability impact would require reporting. (6) The "BES Emergency resulting in automatic firm load shedding" should not apply to the DP. In the existing EOP-004 standard, Distribution Provider is not included and the load shed information still gets reported. (7) The "Voltage deviation on a Facility" event needs to be clarified that the TOP only

reports voltage deviations in its Transmission Operator Area. Because TOPs may view into other Transmission Operator Areas, it could technically be required to report another TOP's voltage deviation because one of its System Operators observed the neighboring TOP's voltage deviation. (8) For the "Loss of firm load greater than 15 minutes" event, the potential for duplicate reporting needs to be eliminated. Every time a DP experiences this event, the DP, TOP and BA all appear to be required to report since the DP is within both the Balancing Authority Area and Transmission Operator Area. Only one report is necessary and should be sent. Given that the existing EOP-004 standard does not include the DP, we suggest eliminating the DP to eliminate one level of duplicate reporting. (9) For the "System separation (islanding)" event, please remove DP. As long as any island remains viable, the Distribution Provider will not even be aware that an island occurred. It is not responsible for monitoring frequency or having a wide area view. (10) For the "System separation (islanding)" event, please remove BA. Because islanding and system separation, involve Transmission Facilities automatically being removed from service, this is largely a Transmission Operator issue. This position is further supported by the approval of system restoration standard (EOP-005-2) that gives the responsibility to restore the system to the TOP. (11) For the "System separation (islanding)" event, please eliminate duplicate reporting by clarifying that the RC should submit the report when more than one TOP is involved. If only one TOP is involved, then the single TOP can submit the report or the RC could agree to do it on their behalf. Only one report is necessary. (12) For the "Generation loss" event, duplicate reporting should be eliminated. It is not necessary for both the BA and GOP to submit two separate reports with nearly identical information. Only one entity should be responsible for reporting. (13) For the "Complete loss of off-site power to a nuclear generating plant", the associated GO or GOP should be required to report rather than the TO or TOP. Maintaining power to cooling systems is ultimately the responsibility of the nuclear plant operator. At the very least, TO should be removed because it is not an operating entity and loss of off-site power is an operational issue. If the TOP remains in the reporting responsibility, it should be clarified that it is only a TOP with an agreement pursuant to NUC-001. All of this is further complicated because NUC-001 was written for a non-specific transmission entity because there was no one functional entity from which the nuclear plant operator gets it off-site power. (14) For the "Complete or partial loss of monitoring capability", partial loss needs to be further clarified. Is loss of a single RTU a partial loss of monitoring capability? For a large RC is loss of ICCP to a single small TOP, considered a partial loss? We suggest as long as the entity has the ability to monitor their system through other means that the event should not be reported. For the loss of a single RTU, if the entity has a solving state estimator that provides estimates for the area impacted, the partial threshold loss would not be considered. If the entity has another entity (i.e. perhaps the RC is still receiving data for its TOP area, the RC can monitor for the TOP) that can monitor their system as a backup, the partial loss has not been met.
No
(1) It is not clear to us what is the driving the need for the Rules of Procedure proposal. NERC is already collecting event and disturbance reports without memorializing the change in the Rules of Procedure. (2) The language potentially conflicts with other subsections in Section 800. For instance, the proposal says that the system will apply to collect report forms "for this section". This section would refer to Section 800. Section 800 covers NERC alerts and GADS. Electronic GADS (eGADS) already has been established to collect GADS data? Will this section cause NERC to have to incorporate eGADS into this report collection system? Incorporating NERC Alerts is also problematic because when reports are required as a result of a NERC alert, the report must be submitted through the NERC Alert system. (3) The statement that "a system to collect report forms as established for this section or standard" causes additional confusion regarding to which standards it applies. Does it only apply to this new EOP-004-2 or to all standards? If it applies to all standards, does this create a potential issue for CIP-008-3 R1.3 which requires reporting to the ES-ISAC and not this clearinghouse?
(1) IC, TSP, TO, GO, and DP should be all removed from the applicability of the standard. Previous versions of the standard did not apply to them and we see no reason to expand applicability to them. IC and TSP are not even mentioned in any of the "Entity with Reporting Responsibility" sections. For the sections that do not mention specific entities, IC and TSP would have no responsibility for any of the events. The TO and GO are not operating entities so the reporting should not apply to them. DP was not included in any previous versions of CIP-001 or EOP-004. Any information (such as load) that was necessary regarding DPs was always gathered by the BA or TOP and included in their reports. There is no indication that this process was not working and, therefore, it should not be changed.

Furthermore, including the DP potentially expands the standard outside of the Bulk Electric System which is contrary to recent statements that NERC Legal has made at the April 11 and 12, 2012 SC meeting. Their comments indicated the standards are written for the Bulk Electric System. What information does a DP have to report except load loss which can easily be reported by the BA or TOP? (2) Measure M2 needs to clarify an attestation is an acceptable form of evidence if there are no events. (3) The rationale box for R3 and R4 should be modified. It in essence states that updating the event reporting Operating Plan and testing it will assure that the BES remains secure. While these requirements might contribute to reliability, these two requirements collectively will not assure BES security and stability. (4) We disagree with the VSLs for Requirement R2. While the VSLs associated with late reporting for a 24-hour reporting requirement include four VSLs, the one-hour reporting requirement only includes three VSLs. There seems to be no justification for this inconsistency. Four VSLs should be written for the one-hour reporting requirement. (5) Reporting of reportable Cyber Security Incidents does not appear to be fully coordinated with version 5 of the CIP standards. For instance, EOP-004-2 R1, Part 1.2 requires a process for reporting events to external entities and CIP-008-5 Part 1.5 requires identifying external groups to which to communicate Reportable Cyber Security Incidents. Thus, it appears the Cyber Security Incident response plan in CIP-008-5 R1 and the event reporting Operating Plan in EOP-004-2 R1 will compel duplication of external reporting at least in the document of the Operating Plain and Reportable Cyber Security Incident response plan. This needs to be resolved. (6) In the effective date section of the implementation plan, the statement that the prior version of the standard remains in effect until the new version is accepted by all applicable regulatory authorities is not correct. In areas where regulatory approval is required, it will only remain in effect in the areas where the regulator has not approved it. (7) On page 6 in the background section, the statement attributing RCIS reporting to the TOP standards is not accurate. There is no requirement in the TOP standards to report events across RCIS. In fact, the only mention of RCIS in the standards occurs in EOP-002-3 and COM-001-1.1. (8) On page 6 in the background section, the first sentence of the third paragraph is not completely aligned with the purpose statement of the standard. The statement in the background section indicates that the reliability objective “is to prevent outages which could lead to Cascading by effectively reporting events”. However, the purpose states that the goal is to improve reliability. We think it would make more sense for the reliability objective to match the purpose statement more closely. (9) On page 7 in the first paragraph, “industry facility” should be changed to “Facility”.
Group
Seattle City Light
Pawel Krupa
Yes
This is a great improvement over the prior CIP and EOP versions. However, please see #4 for overall comment.
Yes
This is a great improvement over the prior CIP and EOP versions. However, please see #4 for overall comment.
No
Seattle City Light follows MEAG and believes this type of activity and process is better suited to NAESBE than it is to NERC Compliance.
1) Seattle City Light follows MEAG and questions if these administrative activities better should be sent over to NAESB? R1: There is merit in having a plan as identified in R1, but is this a need to support reliability or is it a business practice? Should it be in NAESB’s domain? R2, R3 & R4: These are not appropriate for a Standard. If you don’t annually review the plan, will reliability be reduced and the BES be subject to instability, separation and cascading? If DOE needs a form filled out, fill it out and send it to DOE. NERC doesn’t need to pile on. Mike Moon and Jim Merlo have been stressing results and risk based, actual performance based, event analysis, lessons learned and situational awareness. EOP-004 is primarily a business preparedness topic and identifies administrative procedures that belong in the NAESB domain. 2) Seattle City Light finds that even though efforts were made to differentiate between sabotage vs. criminal damage, the difference still appears to be confusing. Sabotage clearly requires FBI notification, but criminal damage (i.e. copper theft, trespassing, equipment theft) is best handled by local law agencies. A key point on how to determine the difference is to always go with the evidence. If you have a hole in the fence and cut grounding

wires, this would only require local law enforcement notification. If there is a deliberate attack on a utility's BES infrastructure for intent of sabotage and or terrorism--this is a FBI notification event. One area where a potential for confusion arises is with the term "intentional human action" in defining damage. Shooting insulators on a rural transmission tower is not generally sabotage, but removing bolts from the tower may well be. Seattle understands the difficulty in differentiating these two cases, for example, and supports the proposed Standard, but would encourage additional clarification in this one area.
Individual
Tony Kroskey
Brazos Electric Power Cooperative
No
Please see the comments submitted by ACES Power Marketing.
No
Please see the comments submitted by ACES Power Marketing.
No
Please see the comments submitted by ACES Power Marketing.
We thank the work of the SDT on this project. However, additional improvements should be made as described in the comments submitted by ACES Power Marketing.
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
Yes
Yes
Oncor takes the position that the proposed objectives as prescribed in Project 2009-01 – Disturbance and Sabotage Reporting, is a "good" step forward. Currently, NERC reporting obligations related to disturbances occurs over multiple standards including CIP-001, EOP-004-1, TOP-007-0, CIP-008-3 and Event Analysis (EA). Oncor is especially pleased that the Event Analysis Working Group (EAWG) is actively working to find ways of streamlining the disturbance reporting process especially to agencies outside of NERC such as FERC, and state agencies. Oncor is in agreement that an addition to the NERC Rules of Procedure in section 800 to develop a Reporting Clearinghouse for disturbance events by the establishment of a system to collect report and then forward completed forms to various requesting agencies, is also a very positive step."
Individual
Denise Lietz
Puget Sound Energy, Inc.
Yes
This draft is a considerable improvement on the previous draft in terms of clarity and will be much easier for Responsible Entities to implement. Puget Sound Energy appreciates the drafting team's responsiveness to stakeholder's concerns and the opportunity to comment on the current draft. The drafting team should revise Requirement R2 to state that the "activation" of the Operating Plan is required only when an event occurs, instead of using the term "implement". "Implementation" could also refer to the activities such as distributing the plan to operating personnel and training operating personnel on the use of the plan. These activities are not triggered by any event and, since it is clear from the measure that this requirement is intended to apply only when there has been a reportable event, the requirement should be revised to state that as well. The drafting team should revise measure M2 to require reports to be "supplemented by operator logs or other reporting documentation" only "as necessary". In many cases, the report itself and time-stamped record of transmittal will be the only documents necessary to demonstrate compliance with requirement R2. Under Requirement R3, using an actual event as sufficient for meeting the requirement for conducting

an annual test would likely fall short of demonstrating compliance with the entire scope of the Operating Plan. R1.2 requires "a process for communicating EACH of the applicable events listed....". If the actual event is only one of many "applicable" events, is it sufficient to only exercise one process flow? If there is no actual event during the annual time-frame, do all the process flows then have to be exercised?
No
The Note at the beginning of Attachment 1 references notifying parties per Requirement R1; however, notification occurs in conjunction with Requirement R2. The term “Adverse Reliability Impact” is used in the threshold section of the event “Damage or destruction of a Facility”. At this time, there are two definitions for that term in the NERC Glossary. The FERC-approved definition for this term is “The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.” If the drafting team instead means to use the definition that NERC approved on 8/4/2011 (as seems likely, since that definition more closely aligns with the severity level indicated by the other two threshold statements) then the definition should be included in the Implementation Plan as a prerequisite approval. In addition, would the threshold of “Results from actual or suspected intentional human action” include results from actual intentional human action which produced an accidental result, meaning, someone was intentionally doing some authorized action but unintentionally made a mistake, leading to damage of a facility? The event “Any physical threat that could impact the operability of a Facility” will require reporting for many events that have little or no significance to reliable operation of the Bulk Electric System. For example, a balloon lodged in a 115 kV transmission line is a “physical threat” that could definitely “impact the operability” of that Facility and, yet, will probably have little reliability impact. So, too, could a car-pole accident that causes a pole to lean, a leaning tree, or an unfortunately-located bird’s nest. The drafting team should develop appropriate threshold language so that reporting is required only for events that do threaten the reliability of the Bulk Electric System. With respect to the event “Unplanned control center evacuation”, the standard drafting team should include the term “complete” in the description and/or threshold statement to avoid having partial evacuations trigger the need to report.
The effective date language in the Implementation Plan is inconsistent with the effective date language in the proposed standard. In addition, the statement of effective date in the Implementation Plan is ambiguous – will EOP-004-2 be effective in accordance with the first paragraph or when it is “assigned an effective date” as stated in the second paragraph? All requirements should be assigned a Lower Violation Risk Factor. Medium risk factors require direct impact on the Bulk Electric System and the language there regarding “instability, separation, or cascading failures” is present to distinguish the Medium risk factor from the High risk factor. Since all of the requirements address after-the-fact reporting, there can be no direct impact on the Bulk Electric System. In addition, if having an Operating Plan under Requirement R1 is a Lower risk factor, then it does not make sense that reviewing that Operating Plan annually under Requirement R4 has a higher risk factor. The shift away from "the distracting element of motivation", i.e., removing "Sabotage" from the equation, runs the risk of focusing solely on what happened, how to fix it, and waiting for the next event to occur. That speaks to a reactive approach rather than a proactive one. There is a concern with the removal of the FBI from the reporting mix. Basically, the new standard will involve reporting a suspicious event or attack to local law enforcement and leaving it up to them to decide on reporting to the FBI. Depending on their evaluation, an event which is significant for a responsible entity might not rise to the priority level of the local law enforcement agency for them to report it to the FBI. While this might reduce the reporting requirements a bit, it might do so to the responsible entity’s detriment. In Attachment 2 - item 4, would it be possible for the boxes be either alpha-sorted or sorted by priority? There is a disconnect between footnote 1 on page 18 (Don't report copper theft) and the Guideline section, which suggests reporting forced intrusion attempt at a substation. Also, in the section discussing the removal of sabotage, the Guideline mentions certain types of events that should be reported to NERC, DHS, FBI, etc., while that specificity with respect to entities has been removed from the reporting requirement.
Individual
Steve Alexanderson
Central Lincoln

No
The new language of R3 and R4 provide nothing to clarify the word “annual.” We note that while a Compliance Application Notice was written on this, Central Lincoln believes that standards should be written so they do not rely on the continually changing CANs. CAN-0010 itself implies that “annual” should be defined within the standards themselves. We suggest: R3 Each Responsible Entity shall conduct a test of the communications process in R1 Part 1.2, not including notification to the Electric Reliability Organization, at least once per calendar year with no more than 15 calendar months between tests. R4 Each Responsible Entity shall conduct a review of the event reporting Operating Plan in Requirement R1. at least at least once per calendar year with no more than 15 calendar months between reviews.
No
1) We appreciate the changes made to reduce the short time reporting requirements. 2) We would like to point out that the 24 hour reporting threshold for “Damage or destruction of a Facility” resulting from intentional human action will still be non-proportional BES risk for certain events. The discovery of a gunshot 115 kV insulator will start the 24 hour clock running, no matter how busy the discoverer is performing restoration or other duties that are more important. The damage may have been done a year earlier, but upon discovery the report suddenly becomes the priority task. To hit the insulator, the shooter likely had to take aim and pull the trigger, so intent is at least suspected if not actual. And the voltage level ensures the insulator is part of a Facility. 3) We also note that the theft of in service copper is not a physical threat, it is actual damage. The reference to Footnote 1 should be relocated or copied to the cell above the one it resides in now. 4) We support the APPA comments regarding small entities.
Yes
Thank you for minimizing the number of necessary reports.
We agree with the comments provided by both PNGC and APPA.
We agree with the comments provided by both PNGC and APPA.
We agree with the comments provided by both PNGC and APPA.
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
No
LADWP has the following comments: #1 - “Any physical threat that could impact the operability of a Facility” is still vague and “operability” is too low a threshold. There needs to be a potential impact to BES reliability. #2 – “Voltage Deviation on a Facility” I think the threshold definition needs to be more specific: Is it 10% from nominal? 10% from normal min/max operating tables/schedules? Another entities 10% might be different than mine. #3 – “Transmission Loss” The threshold of three facilities is still too vague. A generator and a transformer and a gen-tie are likely to have overlapping zones of protection that could routinely take out all three. The prospect of penalties would likely cause unneeded reporting.
LADWP does not have a comment on this question at this time
LADWP does not have any other comments at this time
Group
Arkansas Electric Cooperative Corporation
Philip Huff
No
AECC supports the comments submitted by ACES Power Marketing.
No
AECC supports the comments submitted by ACES Power Marketing.
No
AECC supports the comments submitted by ACES Power Marketing.

Group
Avista
Scott Kinney
Yes
Yes
In general the SDT has made significant improvements to Attachment 1. Avista does have a suggestion to further improve Attachment 1. In Attachment 1 under the 24 hour Reporting Matrix, the second event states "Any physical threat that could impact the operability of a Facility" and the Threshold for Reporting states "Threat to a Facility excluding weather related threats". This is extremely open ended. We suggest adding the following language to the Threshold for Reporting for Any Physical Threat: Threat to a facility that: Could affect an IROL (per FAC-014) OR Could result in the need for actions to avoid and Adverse Reliability Impact This new language would be consistent with the reporting threshold for a Damage event.
Group
PNGC Comment Group
Ron Sporseen
Yes
Yes
We agree with reservations. Our comments are below and we are seeking clarification of the Applicability section of the standard. We are voting "no" but if slight changes are made to the applicability section we will change our votes to "yes". NERC and FERC have expressed a willingness to address the compliance burden on smaller entities that pose minimal risk to the Bulk Electric System. The PNGC Comment Group understands the SDT's intent to categorize reportable events and achieve an Adequate Level of Reliability while also understanding the costs associated. Given the changes made by the SDT to Attachment 1, we believe you have gone a long way in alleviating the potential for needless reporting from small entities that does not support reliability. One remaining concern we have are potential reporting requirements in the Event types; "Damage or destruction of a Facility" and "Any physical threat that could impact the operability of a Facility". These two event types have the following threshold language; "Results from actual or suspected intentional human action" and "Threat to a Facility excluding weather related threats" respectively. We believe these two thresholds could lead to very small entities filing reports for events that really are not a threat to the BES or Reliability. Note: For vandalism, sabotage or suspected terrorism, even the smallest entities will file a police report and at that point local law enforcement will follow their terrorism reporting procedures if necessary, as you've rightly indicated in your "Law Enforcement Reporting" section. We believe extraneous reporting could be alleviated with a small tweak to the Applicability section for 4.1.9 to exclude the smallest Distribution Providers. As stated before, even if these very small entities are excluded from filing reports under EOP-004-2, threats to Facilities that they may have will still be reported to local law enforcement while not cluttering up the NERC/DOE reporting process for real threats to the BES. Our suggested change: 4.1.9. Distribution Provider: with peak load >= 200 MWs The PNGC Comment Group arrived at the 200 MWs threshold after reviewing Attachment 1, Event "Loss of firm load for >= 15 Minutes". We agree with the SDT's intent to exclude these small firm load losses from reporting through EOP-004-2. Another approach we could support is that taken by the Project 2008-06 SDT with respect to Distribution Provider Facilities: 4.2.2 Distribution Provider: One or more of the Systems or programs designed, installed, and operated for the protection or restoration of the BES: • A UFLS or UVLS System that is part of a Load shedding program required by a NERC or Regional Reliability Standard and that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more • A Special Protection System or Remedial Action Scheme where the Special Protection System or Remedial Action Scheme is required by a NERC or Regional Reliability Standard • A Protection System that applies to Transmission where the Protection System is required by a NERC or Regional Reliability Standard •

Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started. We're not advocating this exact language but rather the approach that narrows the focus to what is truly impactful to reliability while minimizing costs and needless compliance burden. One last issue we have is with the language in Attachment 1, Event "BES Emergency resulting in automatic firm load shedding." Under "Entity with Reporting Responsibility", you state that the DP or TOP that "implements" automatic load shedding of >= 100 MWs must report (Also please review the CIP threshold of 300 MWs as this may be a more appropriate threshold). We believe rather than specifying a DP or TOP report, it would be appropriate for the UFLS Program Owner to file the report per EOP-004-2. In our situation we have DPs that own UFLS relays that are part of the TOP's program and this could lead to confusing reporting requirements. Also we don't believe that an entity can "Implement" "Automatic" load shedding but this is purely a semantic issue.
Yes
We appreciate the hard work of the SDT.
Group
Colorado Springs Utilities
Jennifer Eckels
Yes
Yes
Yes
CSU is concerned with the word 'damage'. We support any 'destruction' of a facility that meets any of the three criteria be a reportable issue, but 'damage', if it's going to be included should have some objective definition that sets a baseline.
Individual
James Tucker
Deseret Power
Yes
No
The threshold for reporting is way too low. A gun shot insulator is not an act of terrorism... vandalism yes... and a car hit pole would be reportable on a 138 kv line. these seem to be too aggressive in reporting.
Yes
Group
National Rural Electric Cooperative Association (NRECA)
Barry Lawson
No
NRECA is concerned with the drafting team's proposal to add a new Section 812 to the NERC ROP. NRECA does not see the need for the drafting team to make such a proposal as it relates to the new EOP-004 that the drafting team is working on. The requirements in the draft standard clearly require what is necessary for this Event Reporting standard. NRECA requests that the drafting team withdraw its proposed ROP Section 812 from consideration. The proposed language is unclear to the point of not being able to understand who is being required to do what. Further, the language is styled in

more of a proposal, and not in the style of what would appropriately be included in the NERC ROP. Finally, the SDT has not adequately supported the need for such a modification to the NERC ROP. Without that support, NRECA is not able to agree with the need for this addition to the ROP. Again, NRECA requests that the drafting team withdraw its proposed ROP Section 812 from consideration.
Individual
Michael Gammon
Kansas City Power & Light
No
Requirement 3 requires a test of the communications in the operating plan. A test implies a simulation of the communications part of the operating plan by actual communications being conducted pursuant to the plan. It is not appropriate to burden agencies with testing of communications under a test environment. Recommend the drafting team consider a confirmation of the contact information with various agencies as the operations plan dictates.
No
For the event, "Damage or destruction of a Facility", the "Threshold for reporting" includes "Results from actual or suspected intentional human action". This is too broad and could include events such as damage to equipment resulting from stealing cooper or wire which has no intentional motivation to disrupt the reliability of the bulk electric system. Reports of this type to law enforcement and governmental agencies will quickly appear as noise and begin to be treated as noise. This may result in overlooking a report that deserves attention. Recommend the drafting team consider making this threshold conditional on the judgment by the entity on the human action intended to be a potential threat to the reliability of the bulk electric system. For the event, "Any physical threat that could impact the operability of a Facility", the same comment as above applies. The footnote states to include copper theft if the Facility operation is impacted. Again, it is recommended to make a report of this nature conditional on the judgment of the entity on the intent to be a potential threat to the reliability of the bulk electric system.
No
Rules stipulating the extent of how reported information will be treated by NERC is an important consideration, however, the proposed section 812 proposes to provide reports to other governmental agencies and regulatory bodies beyond that of NERC and FERC. NERC should be treating the event information reported to NERC as confidential and should not take it upon itself to distribute such information beyond the boundaries of the national interest at NERC and FERC.
The flowchart states, "Notification Protocol to State Agency Law Enforcement". Please correct this to, "Notification to State, Provincial, or Local Law Enforcement", to be consistent with the language in the background section part, "A Reporting Process Solution – EOP-004". Evidence Retention – it is not clear what the phrase "prior 3 calendar years" represents in the third paragraph of this section regarding data retention for requirements and measures for R2, R3, R4 and M2, M3, M4 respectively. Please clarify what this means. Is that different than the meaning of "since the last audit for 3 calendar years" for R1 and M1?