# Consideration of Comments on Initial Ballot — Cyber Security 706 (Project 2008-06)
## Date of Initial Ballot: October 20 – November 3, 2010

**Summary Consideration:** The majority of commenters either referred to their comments filed during the comment period or repeated those comments in the ballot. The summary responses for each question in the comment period are provided below:

**Question 1: When reviewing the mapping document posted with the proposed CIP-002-4 standard, do you believe that the proposed standard will lead to an improvement in reliability when compared to the standard it proposes to replace?**

Many of those that voted “No” contended their current risk-based methodology provided a more accurate list of Critical Assets and therefore the proposed criteria in Attachment 1 would not lead to an improvement in reliability. Often, those who commented this way also felt the criteria did not have rigorous system studies as a reliability basis.

The SDT appreciates these comments but believes that although some companies may have a very rigorous risk-based assessment, the implementation of Attachment 1 criteria will overall increase the consistency of Critical Asset identification. The Attachment 1 criteria were developed in response to an external oversight directive in the FERC Order 706. In consideration of this directive, the SDT decided there did not exist across all regions an appropriate third party to provide this type of oversight. Also, external review and oversight carries with it the compliance overhead and arbitration processes analogous to the TFE process. The “bright-line” criteria approach removes the variability of entity-defined methodologies that would prompt the need for external review.

Regarding the need for additional engineering studies, the SDT and volunteer industry participants have expended considerable effort to develop consistent Critical Asset Identification approaches. The team endeavored to include work already required by other standards, and provide some constraints for an entity’s assessment. These approaches, in their various iterations, have been presented to industry for review and comment. The industry provided significant feedback for the need to simplify the Critical Asset identification approach. The Attachment 1 criteria were under development for CIP-010 when the team was asked to use the criteria for the basis of a new CIP Version 4 set of standards. The results of the recent NERC data request were used to assist the team in developing the criteria in Attachment 1.

A few commenters expressed concern that changes to these standards do not address other significant issues. The SDT agrees that other changes ultimately need to be made to the body of CIP cyber security standards, and expects to resume working on those in early 2011. The scope of the changes to the interim CIP-002-4 was deliberately to minimize the impact on the industry while addressing the identified consistency issues with the Critical Asset identification method.

**Question 2: CIP-002-4 Attachment 1 contains criteria that define elements that must be classified as Critical Assets. Do you have any suggestions that would improve the proposed criteria? If so, please explain and provide specific suggestions for improvement.**

In response to question 2, most commenters had suggestions for improvement to the criteria for critical assets listed in Attachment 1. The SDT appreciates these comments and incorporated many of them to improve clarity and consistency. Some of the comments reflected a misunderstanding of a specific criterion, and in those instances the SDT provided additional guidance in the response to comments and modified the associated guidance document for identifying Critical Assets. The SDT believes that the implementation of Attachment 1 criteria will increase the overall consistency of Critical Asset identification. Specific summary analysis of each criterion follows, along with a summary of responses.

**Criterion 1.1** defines as Critical Assets "Each group of generating units (including nuclear generation) at a single plant location with an aggregate highest rated net Real Power capability of the preceding 12 months equal to or exceeding 1500 MW." Commenters requested clarification on the phrase "single plant location." Clarity on this issue was provided in the posted guidance document. "Single plant location" refers to a group of generating units occupying a defined physical footprint and designated as an individual "plant" using commonly accepted generating facility terminology. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant.

Other commenters questioned why we no longer used Contingency Reserve in the criteria, and how the SDT arrived at the value of 1500 MW. In prior postings of CIP-002-4 and CIP-010-1 there was wording about reserve sharing for the threshold. The SDT received feedback that that wording was confusing, that the amount referred to in the reserve sharing was not a specific amount, and that the amounts changed daily. The SDT performed an informal survey of the regions and identified what the megawatt value of the reserve sharing would be for various groups. The SDT used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Balancing Authorities in all regions.

Some commenters suggested the use of capacity factor in the criterion. The SDT debated whether to include it in this criterion. The reason the SDT ultimately chose not to include capacity factor is twofold. First, there is no consistent method to select an appropriate capacity factor, and low capacity factor units may be critical to the system at peak load conditions. Second, there was a concern that some units might fall below the line during major outage periods, taking them off the Critical Asset list one year and putting them back on the list the next year. After considering all of the comments, the SDT chose not change the wording of criterion 1.1.

**Criterion 1.2** defines as Critical Assets "Each reactive resource or group of resources at a single location (excluding generation Facilities) having aggregate net Reactive Power nameplate rating of 1000 MVARs or greater." Some commenters questioned how the value of 1000 MVARs was derived. The value of 1000 MVARs used in this criterion was deemed reasonable for the purpose of determining criticality. Some commenters suggested combining criterion 1.2 with criterion 1.9. FACTS devices in 1.9 are specifically related to IROLs, whereas the reactive resources in 1.2 are not limited to IROL applications. Some commenters suggested that the limit should be set by each Regional Reliability Organization. The issue with using different MVAR values in each region is that it does not meet the objective of uniform application of Critical Asset identification across all entities. After considering all of the comments, the SDT chose not change the wording of criterion 1.2.

**Criterion 1.3** defines as Critical Assets "Each generation Facility that the Planning Coordinator or Transmission Planner designates as required for reliability purposes." Many commenters felt that this criterion places the responsibility for identifying the asset with the wrong entity (not the asset owner). Other commenters noted that the use of the NERC Glossary term "Adverse Reliability Impacts" would help clarify which units should be in this category. Others expressed concern that the criterion should mandate the coordination and approval process between the Transmission Planner and entity that have been designated critical by the Transmission Planner. Still others stated that this criterion is open for auditors to interpret. The SDT responded that the burden for identifying Critical Assets is with the Responsible Entity that is the asset owner. There is no burden or obligation placed on the Planning Coordinator or Transmission Planner to designate any unit as needed for reliability. Based on the comments received, this criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."

**Criterion 1.4** defines as Critical Assets "Each Blackstart Resource identified in the Transmission Operator's restoration plan." Many commenters expressed concern that designating all Blackstart Resources as critical will divert limited resources to protect blackstart facilities that are only used to restore localized load. Others stated that blackstart units deemed critical should be only those identified by the TOP as specified to meet the minimum critical blackstart requirement. Some expressed concern that criterion 1.4 inadvertently provides incentive to utilities to remove resources from the restoration plan, reducing the plan's overall effectiveness.

The SDT specifically chose the NERC Glossary term “Blackstart Resources” to address the concerns expressed. A Blackstart Resource is defined as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.” EOP-005-2 R1.4 states that the restoration plan must include “Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.” The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources. After considering all of the comments, the SDT chose not change the wording of criterion 1.4.

**Criterion 1.5** defines as Critical Assets “The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist.” Some commenters stated that additional qualifying criteria should be added such as "Cranking Paths to critical units as identified in a region’s restoration plan." The SDT noted in its response that there is no longer any NERC requirement to have a region restoration plan. Others asked for clarity around where the point of multiple paths lies in the electrical system. The SDT noted in its response that the point where multiple paths exist in the Cranking Path is the step in the Transmission Operator’s restoration plan per EOP-005-2 R1.5 “Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started” where the Transmission Operator can choose between the next Facilities on the BES to energize. Some commenters expressed concern over the phrase “initial switching requirements.” Based on the comments received, this criterion has been reworded to “The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist, as identified in the Transmission Operator's restoration plan.”

**Criterion 1.6** defines as Critical Assets “Transmission Facilities operated at 500 kV or higher.” Commenters expressed that voltage alone is not a sufficient criterion to determine whether or not an asset is critical to the bulk electric system. They suggested that the SDT should consider using capacity or flows based on power flow studies instead of nominal voltage level as the bright-line. The SDT responded that all Transmission Facilities operated at 500 kV or higher do not require any further qualification for their role as components of the backbone on the Interconnected BES. Furthermore, the SDT does not feel that capacity or power flow analysis (impact-based or risk-based) would lead to a consistent application of the criteria, due to the numerous factors which can impact substation power flows. Such a study would need to be rigorously defined for the industry. The SDT will take this suggestion under consideration for future revisions. After considering all of the comments, the SDT chose not change the wording of criterion 1.6.

**Criterion 1.7** defines as Critical Assets “Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations.” Some commenters provided the suggestion that criterion 1.7 should be reworded to "stations or substations" instead of just "stations" so that it is not implied that it only applies to power plants (stations). Others commented that the SDT should adopt a power flow-based bright-line rather than whether the station is connected to three or more other stations, similar to comments for criterion 1.6. Again, the SDT does not feel that power flow analysis (impact-based or risk-based) may lead to a consistent application of the criteria, due to the numerous factors which can impact substation power flows. Such a study would need to be rigorously defined for the industry. Still others commented that the statement regarding "three or more other transmission stations" is confusing. Does the criterion include stations upstream, downstream, networked or radial? Does the criterion include a radial 345 kV substation connected to a generator? The SDT response is that the intent of criterion 1.7 is to classify as Critical Assets all Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this criterion, since the criterion specifically states “three or more other transmission stations.” The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a

Critical Asset since by definition it cannot be connected to three or more transmission substations. Based on the comments received, this criterion has been reworded to "Transmission Facilities operated at 300 kV or higher at stations or substations interconnected at 300 kV or higher with three or more other transmission stations or substations."

**Criterion 1.8** defines as Critical Assets "Transmission Facilities at a single station location that, if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs)." Some commenters stated that this criterion should be modified because loss of facilities does not cause an IROL violation. An IROL includes a limit and a time constant $T_v$. In order for an IROL violation to occur, the limit must be exceeded for at least the time constant $T_v$. Others commented that additional language should be added to clarify that the TO, LSE, etc. is not responsible for demonstrating IROLs. The SDT responded that according to FAC-014-2, IROLs are established by Transmission Operators, Transmission Planners, and Planning Authorities. The Reliability Coordinator ensures that IROLs are established and are consistent with its methodology. Based on the comments received, this criterion has been reworded to "Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

**Criterion 1.9** defines as Critical Assets "Flexible AC Transmission Systems (FACTS) at a single station location, that, if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs)." Some commenters felt that the term FACTS should be added to the NERC Glossary. FACTS is defined by IEEE as: "Alternating Current Transmission Systems incorporating power electronics-based and other static controllers to enhance controllability and power transfer capability." Commonly accepted terms and definitions do not require an insertion in the NERC Glossary. Some questioned why FACTS devices were singled out in the criteria. FACTS devices were singled out to ensure that there was no confusion as to whether or not they were considered Critical Assets. Other comments followed a similar vein as criterion 1.8. Based on the comments received, this criterion has been reworded to "Flexible AC Transmission Systems (FACTS), at a single station or substation location, that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

**Criterion 1.10** defines as Critical Assets "Transmission Facilities providing the generation interconnection required to directly connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3." Some commenters asked for clarity about the term "directly connected." Additional questions concerned whether the language means total loss of substation or only partial. The intent of this criterion is to ensure the availability of Facilities necessary to support generation Critical Assets. Any Transmission Facility that, if lost, would result in the loss of a Critical Asset identified in criterion 1.1 or 1.3, would need to be classified as a Critical Asset. This might include the partial or total loss of a substation. Based on the comments received, this criterion has been reworded to "Transmission Facilities providing the generation interconnection required to connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets identified by any Generator Owner as a result of its application of Attachment 1, criterion 1.1 or 1.3."

**Criterion 1.11** defines as Critical Assets "Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements." Some commenters stated that criterion 1.11 should be eliminated on the basis that is not based upon BES reliability considerations and that criticality of facilities should not be fuel specific. Criterion 1.11 is based on NUC-001-2 R9.2.2 "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." Since these facilities were deemed so important that a NERC reliability standard was written and adopted to clarify the issue, the SDT determined that this was adequate justification to include them as Critical Assets. Some felt that this criterion should be limited to Transmission Facilities providing offsite power requirements. Since NUC-001-2 is not limited to offsite power requirements, it did not seem appropriate to limit this criterion. After considering all of the comments, the SDT chose not change the wording of criterion 1.11.

**Criterion 1.12** defines as Critical Assets "Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection

Reliability Operating Limits (IROLs).” Comments similar to those for criterion 1.8 concerning IROLs were received on this criterion. Based on the comments received, this criterion has been reworded to “Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed.”

**Criterion 1.13** defines as Critical Assets “Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes.” Some commenters stated that the wording of this criterion will inadvertently bring in all SCADA systems with the capability of shedding load even if such SCADA systems are in fact not planned or operated to perform load shedding. This was not the intent of the SDT. Other commenters stated that this item needs to be clarified to confirm that it applies to a single common control system only, and not multiple but separate “like” systems that in aggregate are capable of load shedding up to 300 MW. Also, the criterion needs to be clarified to confirm that it applies to systems “configured” for automatic load shedding, not simply just “capable” of load shedding. Still others stated that this criterion should use the same "bright-line" as generation, 1500 MW. This criterion was intended to include as Critical Assets regional Under Frequency Load Shedding and Under Voltage Load Shedding schemes. Based on the comments received, this criterion has been reworded to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”

**Criterion 1.14** defines as Critical Assets “Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator.” No commenter stated that this criterion was inappropriate for Reliability Coordinators. Several commenters stated that the term “control center” needs to be defined in the NERC Glossary. At this time, the SDT is choosing not to add control center to the NERC Glossary. The team felt that defining this term under this proposed version of the standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. This term is used in other approved NERC standards already in effect. Many commenters stated that control centers for Balancing Authorities (BA) and Transmission Operators (TOP) need bounds. It was stated that a small BA or TOP that does not have any other Critical Assets does not need all of the Requirements in CIP-003-4 to CIP-009-4 applied to them.

After considerable discussion, it was determined by the SDT that these “small” BAs and TOPs could be addressed in the next version of the standard. Based on the comments received, this criterion has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion 1.16 (the posted criterion 1.16 has been removed, see explanation below) has been added which states “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion 1.17 has been added which states “Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”

**Criterion 1.15** defines as Critical Assets “Each control center or backup control center used to control generation identified as a Critical Asset, or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection.” Comments received on this criterion were similar to those received on criterion 1.1 and criterion 1.14. Based on the comments received, this criterion has been reworded to “Each control center or backup control center used to control generation at multiple plant locations, for any generation Facility or group of generation Facilities identified in criteria 1.1, 1.3, or 1.4. Each control center or backup control center used to control generation equal to or exceeding 1500 MWs in a single Interconnection.”

**Criterion 1.16** defines as Critical Assets “Any additional assets that the Responsible Entity deems appropriate to include.” This criterion was placed in Attachment 1 to provide Responsible Entities the flexibility to include addition items on their Critical Asset list that did not meet any other criterion in Attachment 1. Many commenters stated that this was contrary to providing a bright-line for Critical Asset identification. In addition, it has the potential of causing issues in compliance audits. For these reasons, criterion 1.16 in its current form was deleted from Attachment 1.

**Question 3: Requirement R1 of draft CIP-002-4 states, "Critical Asset Identification — Each Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the criteria contained in CIP-002-4 Attachment 1 – Critical Asset Criteria. The Responsible Entity shall review this list at least annually, and update it as necessary." Do you agree with the proposed Requirement R1?**

The majority of commenters that disagreed with Requirement R1 suggested changes to the wording that is present in the existing CIP-002-3. The SDT responded that the scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. The phraseology mentioned exists in the existing CIP-002-3 standard. The SDT expects the phraseology to be resolved in the next version. Others stated that their objection was with the wording in Attachment 1. The SDT directed them to the responses offered to their comments in question 2.

**Question 4: Requirement R2 of draft CIP-002-4 states, "Using the list of Critical Assets developed pursuant to Requirement R1, each Responsible Entity shall develop a list of associated Critical Cyber Assets performing a function essential to the operation of the Critical Asset. For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes. Each Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics". The requirement then lists characteristics using the same text that is contained in the existing CIP-002-3 R3. Do you agree with the proposed Requirement R2?**

Of commenters that disagreed with Requirement R2, the majority suggested changes to the wording that is present in the existing CIP-002-3. The SDT responded that the scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. The phraseology mentioned exists in the existing CIP-002-3 standard. The SDT expects the phraseology to be resolved in the next version. Some commenters had questions about the 15-minute qualifier. The SDT's response is that this phrase is inserted to limit the scope to "real-time" operations, which is not a NERC defined term. Several commenters had suggested wording to clarify the requirement. Based on the comments received, Requirement R2 has been reworded to:

R2. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R1, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. The Responsible Entity shall update this list as necessary, and review it at least annually.

For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed Attachment 1, criterion 1.1.

For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

- The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- The Cyber Asset uses a routable protocol within a control center; or,
- The Cyber Asset is dial-up accessible.

**Question 5: Do you agree with the proposed implementation plan for the Version 4 standards?**

In response to question 5, some commenters asked for new terms to be added to the NERC Glossary.  At this time, the SDT is choosing not to add terms to the NERC Glossary since defining these terms would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. These terms are used in other approved NERC standards already in effect.

APPA's review of the associated implementation plan for CIP-002-4 identified a potential inconsistency between the Implementation Plan and the Reliability Standard.  The Reliability Standard clearly provides that updates to the Critical Asset list will be made at the time of the annual review. However, the Implementation Plan is not as clear.  Requirements R1 and R2 were modified to clarify that the update is ongoing, and the review must occur at least annually.  Several entities requested that the implementation plans be combined.  A NERC Standard Implementation Plan address assets that are in place and applicable the date the standard becomes effective.  It is retired once the Implementation Plan is completed. The Implementation Plan for Newly Identified Critical Cyber Asset and Newly Registered Entities addresses assets that are identified in the future and future Registered Entities and is an ongoing plan that has no expected retirement date.

Some entities asked for a provision for extensions to the implementation plan for good cause.  The suggested modification proposes an exception process to a mandatory standard, and the SDT refers the entities to the discussion on technical feasibility exceptions in the FERC Order. Specifically, the oversight framework which must be in place is summarized in paragraph 222.

Some commenters felt the implementation plan was too aggressive.  The SDT believes there is precedent showing this implementation period is reasonable.  Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets.  This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset.

Some entities requested a 24-month implementation after the effective date of the standard, and indicated that the proposed plan too complicated. The SDT has simplified the implementation plan to reference the Effective Date of CIP-002-4 through CIP-009-4 which is 8 calendar quarters after regulatory approval.

**Question 6: Do you agree with the proposed revisions to the implementation plan for newly identified CCAs and Responsible Entities?**

In response to question 6, some commenters noted conforming changes that needed to be made in the implementation plan for newly identified CCAs and Responsible Entities.  The SDT made these changes and will post them in the next ballot.  Most other comments were similar to those offered in question 5, for which the SDT offered the same responses.

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

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| Kirit S. Shah | Ameren Services | 1 | Negative | 1. (a) The proposed bright line criteria are not based on any studies or performance testing. (b) The proposed bright line criteria do not address proximity to load centers or the impact to system flows or voltages in those load centers. (c)Also, we believe that impact on the BES should be evaluated for the Critical Asset using the performance requirement contained in the existing mandatory standards. This would provide consistency between CIP-002 and other standards. In this regard, we suggest that for the facilities identified in the bright line criteria, perform powerflow and stability simulations to assess the impact to the BPS of the outage of these facilities, similar to the tests performed for TPL-003 and 004. If there is an impact (that is not meeting the performance criteria), then the facility is to be considered as critical. If there is no such impact, then the facility is not be considered as critical. If there is a concern for a multi-prong attack, then similar reliability assessment should be performed for such scenarios. (d)Further, the bright line criteria will include many more facilities as critical assets with minimal to no improvement to reliability and would require significant resource commitment to meet the proposed implementation schedule.<br><br>2. We offer some comments/suggestions and also have some questions/comments to the bright line criteria (Attaachment 1): (a) The term “Facilities” should be changed to “substations and switchyards” throughout Attachment 1 as NERC glossary of terms include “lines” in the definition also. Is it SDT’s intention to include hundreds of miles of lines as critical asset? (b) The term “single station location” and “single plant location” used throughout Attachment 1 need to be defined to avoid confusion whether a single location mean one building or several buildings or stations within a defined geographical boundary or a fenced area. (c) Specific comments to Attachment 1 : 1.1 - Are there any reliability impact studies to support 1500 MW? We believe that several events larger than this number have occurred and the BES has performed as designed, |

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

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| | | | | without any loss of load, or significant impact on reliability. 1.6 - We disagree that all transmission facilities operated at 500 kV or greater are “critical”. Again, system studies should be conducted to take into account the impact that the asset has on the reliable operation of the BES before determining that an asset is a Critical Asset. 1.7 - We disagree that all transmission facilities that are operated at 300 kV or above and are interconnected with three or more transmission substations are “critical. System studies should be conducted to take into account the impact that the asset has on the reliable operation of the BES before determining that an asset is a Critical Asset. 1.8 - Wording for this criterion should be changed to “Transmission substations and switchyards that the Planning Coordinator or Transmission Planner designates that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL). This change would make this criterion consist with FAC-010/FAC-014. 1.12 - We believe that the criterion reads ok, but the rationale document for this criterion implies that purpose of SPS/RAS is to prevent disturbance that would result in excursion beyond IROLs. This may not be true in all cases. 1.13 - Wording for this criterion should be changed to “Common control system(s) capable of performing automatic load shedding of 300 MW or more with a single operation”. 1.15 - Same comments as for 1.1 above. 1.16 - Wording for this criterion should be changed to “Any additional assets owned by the Responsible Entity that the Responsible Entity deems appropriate to include.” 3. CIP-002-4, R2 : (a) The word “associated” could mean anything to do with a Critical Assets which is too broad of a term and needs to be defined to avoid confusion. (b)The phrase "could adversely impact the reliable operation" is unclear and vague. What magnitude of "adverse impact" should be considered? Also what is being defined as the Reliable Operation? This phrase should be more clearly defined, otherwise it could introduce different interpretations in the compliance audits. 4. The implementation plan is very confusing. |

**Response**: Thank you for your comments.

(1) The SDT and volunteer industry participants have expended considerable effort to develop consistent Critical Asset Identification approaches. The team endeavored to include work already required by other standards, and provide some constraints for an entity’s assessment. These approaches, in their various iterations, have been presented to industry for review and comment. Significant feedback from the industry indicated the need to simplify the Critical Asset identification approach. We welcome your suggestions for improvement to the criteria. The Attachment 1 criteria were under development for CIP-010 when the team was asked to use the criteria for the basis of a new CIP Version 4 set of standards. The results of the recent NERC data request were used to assist the team in developing the criteria in Attachment

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| 1. Bright-line criteria by its very nature may overreach in some areas and under-reach in others, with the end result being a more protected system on average.<br><br>The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. The SDT does not feel that a power flow analysis (impact-based or risk-based) may lead to a consistent application of the criteria, due to the numerous factors which can impact substation power flows. Such a study would need to be rigorously defined for the industry.<br><br>(2) a) A Transmission Line can be considered a Critical Asset if it meets the criteria in Attachment 1. It would then be evaluated for possible Critical Cyber Assets, which would be afforded the cyber security protection outlined in CIP-003 to CIP-009. It is not the Critical Asset that falls under CIP-003 to CIP-009, but the Critical Cyber Asset.<br><br>b) The guidance document posted by the SDT provides direction on the location issue. "Single plant location" refers to a group of generating units occupying a defined physical footprint and designated as an individual "plant" using commonly accepted generating facility terminology. Adjacent plants would be defined using the same criteria. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant.<br><br>c) Item 1.1 - In prior versions we had wording about reserve sharing for the threshold. We received feedback that that wording was confusing, that the amount referred to in the reserve sharing was not a specific amount, and that the amounts changed daily. We did an informal survey of the regions, and we identified what the megawatt value of the reserve sharing would be for various groups. The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BAs in all regions.<br><br>Items 1.6 and 1.7 – You propose to add the criteria that the Responsible Entity can determine through a risk-based evaluation that destruction, degradation or unavailability of certain assets will have no impact outside the local area and will not cause BES instability, separation, or cascading outages. The SDT does not feel that a power flow analysis (impact-based or risk-based) may lead to a consistent application of the criteria, due to the numerous factors which can impact substation power flows. Such a study would need to be rigorously defined for the industry. We thank you for your proposal and will take it under consideration for future revisions. Criterion 1.7 has been reworded to "Transmission Facilities operated at 300 kV or higher at stations or substations interconnected at 300 kV or higher with three or more other transmission stations or substations."<br><br>Item 1.8 – This criterion has been changed to "Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."<br><br>Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."<br><br>Item 1.15 –In the development of this criterion, the drafting team used 1500 MW as a bright-line for aggregate generation controlled based on | | | | |

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| the bright-line used in Part 1.1. The drafting team specified a single Interconnection because it is more likely that the span of control of the generation control center may cross multiple BA or RSG areas or even regions and Interconnections.<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot.<br><br>(3) The phrase "associated" exists in the existing CIP-002-3 standard. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. The phrase "adversely impact" limits the scope of the evaluation of Critical Cyber Assets to those that can affect the reliable operation of 1500MW or more of generation at a single plant location.<br><br>(4) The implementation plan is a modification of the implementation plan for version 3 of the CIP standards. | | | | |
| Paul B. Johnson | American Electric Power | 1 | Negative | Overall, AEP is supportive of the efforts and the general concepts of this draft; however, there are a few refinements that will enhance the requirements and remove ambiguity. AEP encourages the SDT to consider the items below in a future draft of the standard: AEP would contend that there are regional differences that would be relevant to determine a MW threshold for generators. We support the concept that was contained in the last draft that made the determination based on the capacity reserves. However, the prior language would need to be revisited to ensure that value was fixed for a period of time. In addition, requirement 2.2 uses the term control center (also used in attachment 1) that is not a NERC defined term. This will introduce ambiguity to implementation. There has been ongoing confusion regarding the difference between "control centers" and "control rooms." We do not believe that a "control room" at a power plant or a substation would be considered a "control center." There is language in the NERC Security Guideline for Electricity Sector: Identifying Critical Assets document that the SDT should consider and incorporate into the NERC Glossary. Net real power capability testing is defined in MOD-024 standards that have yet to be FERC approved. Furthermore, not all of the regions have defined the parameters for the capability testing. |
| **Response**: Thank you for your comments.<br><br>Item 1.1 - In prior versions we had wording about reserve sharing for the threshold. We received feedback that that wording was confusing, that the amount referred to in the reserve sharing was not a specific amount, and that the amounts changed daily. We did an informal survey of the regions, and we identified what the megawatt value of the reserve sharing would be for various groups. The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BAs in all regions.<br><br>At this time, the SDT is choosing not to add control center to the NERC Glossary. We feel defining this term under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. This term is used in other approved NERC standards | | | | |

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| already in effect.<br><br>CIP-002-4 does not require net real power capability testing. | | | | |
| John Bussman | Associated Electric Cooperative, Inc. | 1 | Negative | Please review the submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Gordon Rawlings | BC Transmission Corporation | 1 | Negative | Critical Assets List comments 1.7. Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations The present wording uses an arbitrary numbers of stations, the number of stations is immaterial BCH recommends the “Transmission Facilities operated at 300 kV or higher that if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs). 1.13. Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes. A clear definition of common control system(s) is required. Is under frequency or under voltage load shedding schemes considered control systems? The load shedding of 300 MW or more does it include firm or interruptible load or both? 1.16. Any additional assets that the Responsible Entity deems appropriate to include. To encourage reliability the additional assets deemed appropriate by a Responsible Entity should not be auditable. |
| **Response**: Thank you for your comments.<br><br>Item 1.7 – In order to be more accurate in terms of the impact, the drafting team thought that it was more appropriate to refer to the number of connected transmission substations instead of using IROLs. The intent was to avoid double-circuit conditions and to include facilities that are actually more a part of the network than simple substations with double circuits between them. This includes upstream, downstream, radial and networked substations.<br><br>Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot. | | | | |

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| Joseph S. Stonecipher | Beaches Energy Services | 1 | Negative | See my comments in the survey on the NERC Website for Cyber Security 706. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Donald S. Watkins | Bonneville Power Administration | 1 | Negative | Please refer to BPA comments submitted during the formal comment period on 10/26/10. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Tony Kroskey | Brazos Electric Power Cooperative, Inc. | 1 | Negative | See response submitted on the Comments Form. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Paul Rocha | CenterPoint Energy | 1 | Negative | CenterPoint Energy appreciates the work of the SDT and feels that the proposed Standard is very close. As stated in comments previously submitted, CenterPoint Energy belives criteria 1.11 in Attachment 1 is unnecessary and should be deleted or, if the SDT feels some criteria regarding nuclear facilities is needed then it should be limited to transmission facilities that directly connect the nuclear generator output to the transmission system. With either of these two changes CenterPoint Energy beleives it could support the proposed Standard. |
| **Response**: Thank you for your comments.<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2, "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." Since these facilities were deemed so important that a NERC standard was written and adopted to clarify the issue, the SDT determined that this was adequate justification to include them as Critical Assets. | | | | |
| Michael B Bax | Central Electric Power Cooperative | 1 | Negative | Please review submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |

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| Jack Stamper | Clark Public Utilities | 1 | Negative | Attachment 1, part 1.14 would make a control centers performing the functional obligation of a TOP a Critical Asset. This apparently would be the case even if a TOP's control center only performed these functions on facilities that are not critical. Small entities have in some cases been forced by Balancing Authorities and former Transmission Operators to register as TOPs. Many of these TOPs operate systems with no assets that qualify as Critical Assets under any of the other Attachment 1 criterion. Some of these TOPs operate systems that do not have any Bulk Electric System facilities. It is unreasonable to designate these utilities dispatch centers as Critical Assets. Part 1.14 should be modified as follows: 1.14. Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator over any facilities determined to be Critical Assets as determined in Attachment 1, criterion 1.1 through 1.13. |
| **Response**: Thank you for your comments.<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection." | | | | |
| John K Loftis | Dominion Virginia Power | 1 | Negative | Dominion conceptually supports bright line criteria for determining critical assets. However, we cannot vote in favor at this time because we believe that changes are needed in Table 2 that recognize the implementation for infrastructure (physical and electronic security) should be equal to, or longer than, that required for training. We also believe that the bright line criteria for generation control center needs further effort. Please see more specific comments/recommendations submitted by Dominion. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| George S. Carruba | East Kentucky Power Coop. | 1 | Negative | EKPC would suggest rewording R2 to say: "For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those interconnected Cyber Assets that collectively could adversely |

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| | | | | impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes." |
| **Response**: Thank you for your comments. Requirement R2 has been changed based on industry comments received. | | | | |
| Ralph Frederick Meyer | Empire District Electric Co. | 1 | Negative | EDE understand that NERC standards are a minimum requirement and regions can look at their own operating criteria and determine if they need additional protection at lower Megawatt bright-lines. EDE agrees with APPA in that they are concerned that the use of the “Real Power Capability of the preceding 12 months” would bring in unnecessary volatility to applicability of this standard to certain groups of generating units. To alleviate this volatility we agree that generation owners should use the facility ratings which are calculated and communicated under FAC-009-1 R2.<br>EDE agrees with Cleco in that there is a dichotomy between 1.1. that states generation “equal to or exceeding 1500 MW” and 1.15. that states control centers that control generation “greater than an aggregate of 1500 MWs” There should be consistency between the two.<br>EDE agrees with AAPA in that:APPA suggests that the designation of facilities be based on studies conducted under the TPL standards to justify the designation. Also, the use of NERC Glossary of term: “Adverse Reliability Impacts” will help clarify which units should be in this category. We are also concerned that the PC or TP will be looking at local vs. wide area reliability. There are some cases where the PC can designate Must Run units for temporary situations so this must be clarified within the criteria. APPA proposes the following rewording of criteria 1.3: 1.3 Each generation Facility that the Planning Coordinator or Transmission Planner designates as required to avoid BES Adverse Reliability Impacts for 1 year or longer.<br>EDE agrees with AAPA in that Item 1.4 inadvertently incentivizes utilities to remove blackstart resources from the restoration plan if these resources are not critical to an effective regional restoration plan, reducing the plan’s overall effectiveness. Therefore, we believe there should be a threshold for Blackstart Resources, similar to nearly all other elements being considered in Attachment 1. This would allow utilities the freedom to include numerous resources in the Transmission Operators restoration plan without being swept into being identified as a critical asset. EDE agrees with LES in that this language should be changed to “Each Blackstart Resource identified in the Transmission Operator’s restoration plan as used to directly start |

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| | | | | generation identified as a Critical Asset, or identified in the Transmission Operator's restoration plan as used to directly start generation greater than an aggregate of 300 MW."<br>1.5 EDE does request clarification of criteria 1.5: Where does this point of multiple paths lay in the electrical system? Does this include only the Generator Step-up Transformer, or does it include the whole substation where multiple transmission paths depart to a single generator?<br>EDE believes that criteria 1.8 and 1.9 should be reworded to "station or substation" instead of just "station" so that it is not implied that it only applies to power plants (station).<br>EDE seeks verification from the SDT that the SPS they refer to in criteria 1.12 is for wide area protection only.<br>EDE agrees with APPA suggested change in 1.13: 1.13. Common control system(s) configured to perform automatic load shedding of 300 MW or more within 15 minutes. EDE agrees with APPA in that we can accept the bright-line of 300 MW if the wording is changed to that stated above, but we still see this bright-line as an arbitrary threshold based on a quantity that has no BES operational significance. Rather, 300 MW is a DOE threshold for electric event reporting.<br>EDE agrees with APPA in that criteria 1.14. is overly broad because it includes all BA and TOP control centers regardless of size. EDE asks that the SDT revise this criteria to include a bright-line with similar impact as those in 1.1 and 1.15.<br>EDE agrees with APPA revised wording: 1.14. Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator with a minimum of 1500 MW of resources under its control. EDE agrees with AAPA in that we cannot support this standard revision without some form of bright line cutoff to exclude small BAs and TOPs that cannot cause instability or uncontrolled separation of the BES. However, we will support inclusion of "ALL BA and TOP control centers" only when this standard is revised to provide for a tiered (High, Medium and Low) categorization of Critical Assets, such as the SDT's draft CIP-010-1 proposal.<br>In the NERC Draft CIP-002-4 webinar it was stated that a control center in criteria 1.15 is understood to be controlling multiple units. EDE agrees with APPA recommendation that the SDT clarify the wording in criteria 1.15 to coincide with this understanding: 1.15. Each control center or backup control center used to control multiple generation units identified as Critical |

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| | | | | Assets designated under criterion 1.3 or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection. EDE agrees with AAPA in that 1.16 should be removed from the Attachment 1 criteria. We expect that registered entities may voluntarily protect assets above and beyond the ones listed in these criteria. However, we just do not see the reliability benefit of imposing a compliance liability to those self identified critical assets. We feel that the NERC and Regional compliance staff will waste valuable time and resources evaluating entity compliance with cyber security controls for assets that are outside of the scope of this standard For newly identified Critical Assets, a 24 month implementation is provided for Entities that have never identified a Critical Asset under the version 3 standards, with only 18 months provided for Entities with existing Critical Assets. We believe the SDT has developed a sound approach with this delineation. However, we also believe the 24 month implementation should be expanded to include Entities that may have existing Critical Assets, but have never identified a Critical Asset of a given type, i.e., generating unit, transmission facility, control center, etc. For example, if a company had a control center that was previously identified as critical, but version 4 results in their first generating unit being identified, then we would propose that they be given 24 months to become compliant as they are working on their first generating unit. EDE agrees with AAPA in that a review of the associated Implementation Plan for CIP-002-4 has identified a potential inconsistency between the Implementation Plan and the Reliability Standard. The Reliability Standard clearly provides that updates to the Critical Asset list will be made at the time of the annual review. However, the Implementation Plan is not as clear. We would request modification to the Implementation Plan such that it reflects the intent of the Reliability Standard. The Implementation Plan does not adequately address when a “New Asset” that does meet the CIP-002-4 criteria for being a Critical Asset after its commissioning will need to be in compliance. EDE agrees with APPA in that the intent of the Reliability Standard indicates that the post-commissioned New Asset will become a Newly Identified Critical Asset upon the subsequent Annual Review and only at the time of this Annual Review. Further that the timeline associated with this Newly Identified Critical Asset starts with the date of the Annual Review. We raise this point because we are concerned about the potential impact for confusion associated with multiple review dates or continuous reviews of the assets contained within numerous CIP activities. If an entity |

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| | | | | has multiple Cyber Assets, the entity would likely have multiple Annual Reviews dates. |

**Response**: Thank you for your comments.

Item 1.1 – The SDT notes your concern that the use of the "Real Power Capability of the preceding 12 months" would bring in unnecessary volatility to applicability of this standard to certain groups of generating units. The drafting team used time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used. The 12-month time period was used so that seasonal ratings would not be an issue for generating plants that operate near the 1500 MW bright-line. The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BAs in all regions.
Criterion 1.15 has been modified to conform to the MW wording in 1.1.

Item 1.3 – This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."

Item 1.4 – A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." EOP-005-2 R1.4 states that the restoration plan must include "Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit." The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources.

Item 1.5 – The point where multiple paths exist in the Cranking Path is the step in the Transmission Operator's restoration plan per EOP-005-2 R1.5, "Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started," where the Transmission Operator can choose between the next Facilities on the BES to energize.

Items 1.8 & 1.9 - The SDT changed "stations" to "stations or substations."

Item 1.12 – Since this item only applies to SPSs that have IROLs associated with them, local area SPSs are not included.

Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."

Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset

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| identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."<br><br>Item 1.15 –This criterion has been changed to "Each control center or backup control center used to control generation at multiple plant locations, for any generation Facility or group of generation Facilities identified in criteria 1.1, 1.3, or 1.4. Each control center or backup control center used to control aggregate generation equal to or exceeding 1500 MWs in a single Interconnection."<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot.<br><br>Implementation Plan issues - Thank you for your comments. Requirements R1 and R2 were modified to clarify that the update is ongoing, and the review must occur at least annually. The text reference was removed from the Implementation Plan. | | | | |
| George R. Bartlett | Entergy Corporation | 1 | Negative | Switchyards serving nuclear facilities should not be automatically classified as critical assets. - The fact that a BES switchyard serves a nuclear facility should not in itself qualify the switchyard as a critical asset. While nuclear units and their support facilities may qualify as critical assets under a separate set of criteria, they should not automatically be designated as critical to the BES without some measure of the impact of the loss of the facility on BES reliability.<br>All blackstart units and associated cranking paths should not be automatically classified as critical assets. - Blackstart units may be useful in the restoration of the BES following a large scale outage, but they are not necessarily essential to the reliability of the BES under normal operation. Blackstart units should not automatically be designated as critical to the BES without some measure of the impact of the loss of the facility on BES reliability. |
| **Response**: Thank you for your comments.<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2, "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." Since these facilities were deemed so important that a NERC standard was written and adopted to clarify the issue, the SDT determined that this was adequate justification to include them as Critical Assets.<br><br>Item 1.4 – A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." The SDT feels that these units must be classified as Critical Assets. It should be noted that not all blackstart generators are Blackstart Resources. | | | | |

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| Dennis Minton | Florida Keys Electric Cooperative Assoc. | 1 | Negative | Cost prohibitive for small entities that have little to no material impact to the BES. |
| **Response**: Thank you for your comments. Cost is only one of many issues that must be considered in the cyber security of the BES. | | | | |
| Gordon Pietsch | Great River Energy | 1 | Negative | GRE commented during the comment period and the drafting team should refer to those comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Ajay Garg | Hydro One Networks, Inc. | 1 | Negative | Hydro One is casting a negative vote for the following reasons: 1. We do not believe the standard will result in an improvement in reliability since the revisions merely replace the risk-based assessment methodology with a list of criteria that will ultimately result in inclusion of facilities on the Critical Assets list that are non-impactive on the BES. 2. We do not agree with criteria 1.6 and 1.7 in Attachment 1 as written. Application of these criteria would result in the inclusion of facilities that will have no impact on the BES reliability. We believe that the list of applicable facilities should be determined following an impact-based assessment to be performed by the Reliability Coordinator. If necessary, an additional requirement that requires the RC to have a risk-based assessment methodology and to conduct/review the assessment should be included. We therefore propose the following wording to replace 1.6 and 1.7 in Attachment 1: 1.6 Transmission facilities operated at 500 kV or higher, unless the annual review performed by the RC determines that destruction, degradation or unavailability of those assets will have no impact outside the local area and will not cause BES instability, separation, or cascading outages. 1.7 Transmission Facilities operated at 300 kV or higher to less than 500 kV at stations interconnected at 300 kV or higher with three or more other transmission stations, unless the annual review performed by the RC determines that destruction, degradation or unavailability of those assets will not have impact outside the local area and will not cause BES instability, separation, or cascading outages. 3. We do not agree with the removal of the exclusion that applies to facilities regulated by the Canadian Nuclear Safety Commission from the Applicability Section, This explicit statement makes it clear that CIP standards do not apply to those facilities |

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| | | | | which would not be the case if it were removed. |
| **Response**: Thank you for your comments.<br><br>1) The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology.<br>2) Items 1.6 and 1.7 – The SDT does not feel that a power flow analysis (impact-based or risk-based) may lead to a consistent application of the criteria, due to the numerous factors which can impact substation power flows. Such a study would need to be rigorously defined for the industry. We thank you for your proposal and will take it under consideration for future revisions.<br>3) The SDT is aware that the removal of the nuclear plant exclusion in response to a FERC order brought Canadian nuclear plants into the CIP standards. That was unintentional and will be corrected in the revised standards next posted for ballot. | | | | |
| Bernard Pelletier | Hydro-Quebec TransEnergie | 1 | Negative | 1- CIP-002-4, Attachment 1, as posted, is a simple list of assets that appears without mention of any performance based requirement. We believe that to be an effort to "cast a wider net" and capture more assets without qualifying their actual criticality. Attachment 1 inclusion criteria for critical assets should be based on critical functions of assets like: system restoration, voltage control, maintaining load/generation balance, maintaining flows within IROL/SOL, critical SPS. This list should not rely on substation voltages or amount of MW. 2- Also, the term "group of generating unit" in CIP-002-4, R2 and 1.1 of Attachment 1 is not clear. Does it mean a generating station? A group of units sharing the same transformer? 3- The 15 minutes delay of reliable operation referred in CIP-002-4, R2 is not clear too. How it will be determine that operations are not reliable after 15 minutes? Does this 15 minutes period is the Disturbance Recovery Period referred in BAL-002 Reliability Standard? 4- Hydro-QuÃ©bec does not agree with the removal of item (4.2.1) from the revised CIP002-4. We consider that the Canadian Nuclear Safety Commission should still be exempted from the standard CIP-002. 5- The cross references are still part of some CIP and it's sometimes makes the interpretation of the requirements more complex. For example CIP-007-4 R5.1.3 “Account Management” indicates the review should be done annually in accordance with CIP-004-4 E4 but the R4.1 indicates the review should be done quarterly. A table that explains the different requirements instead of a cross reference would be more useful. |
| **Response**: Thank you for your comments.<br><br>1) The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology. | | | | |

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| 2) Item 1.1 – The guidance document posted by the SDT provides direction on the location issue. “Single plant location” refers to a group of generating units occupying a defined physical footprint and designated as an individual “plant” using commonly accepted generating facility terminology. Adjacent plants would be defined using the same criteria. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant.<br>3) The reference to 15 minutes was inserted to keep the scope to “real-time” operations, an undefined term.<br>4) The SDT is aware that the removal of the nuclear plant exclusion in response to a FERC order brought Canadian nuclear plants into the CIP standards. That was unintentional and will be corrected in the revised standards next posted for ballot. | | | | |
| Walter Kenyon | KAMO Electric Cooperative | 1 | Negative | Please review submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Stan T. Rzad | Keys Energy Services | 1 | Negative | The SDT is commended on making significant headway on the version 4 standards. However, there are significant additional improvement that should be made to make the criteria of Attachment 1 less arbitrary and that truly measures those assets that can have an Adverse Reliability Impact. Also, the standard is still unclear in several areas, such as how to identify CCAs at a substation if a substation is determined to be a CA that needs to be clarified. Please see FMPA's comments submitted through the formal comment process for more specific detail and proposed alternatives. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Larry E Watt | Lakeland Electric | 1 | Negative | LAK cannot support this standard revision without some form of bright line cutoff to exclude small BAs and TOPs that cannot cause instability, cascading or uncontrolled separation of the BES. |
| **Response**: Thank you for your comments.<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.” | | | | |
| John W Delucca | Lee County Electric Cooperative | 1 | Negative | General Comments & Information Security Best Practices NERC distributed a questionnaire to responsible entities to gauge the impact of the proposed changes to CIP-002-4. The bright line criteria has changed since this |

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| | | | | assessment was performed and will result in the inclusion of additional assets being categorized as Critical Assets. Existing studies prove that many of these assets are not Critical Assets and do not impact the reliability of the BES. The existing CIP3 - CIP9 standards are not being modified with the version four release even though there are many opportunities to improve these standards. A good example can be seen with the Technical Feasibility Exception (TFE) process. Why are entities and regulatory agencies being forced to spend a significant amount of time processing TFE's because requirements don't make sense? A good example is the common TFE for routers and switches that do not and cannot run antivirus software. Expanding the scope of these labor intensive and non-value added processes will only deter entities from implementing effective security measures and best practices. A prudent approach would be to adjust the bright line criteria to ensure that the assets being included in the scope of the version four standards are truly Critical Assets. Once the security control standards are improved, the scope can be expanded to include medium and low impact cyber systems.<br>Attachment 1 & Criteria Suggestions Attachment 1: o Paragraph 1.14 includes the Transmission Operator (TOP) function in addition to the Reliability Coordinator (RC) and Balancing Authority (BA) functions. In CIP10 the concept of a true "risk based" approach to the application of security requirements was proposed in the purpose section of the document as follows: Purpose: To identify and categorize BES Cyber Systems that execute or enable functions essential to reliable operation of the BES, for the application of cyber security requirements commensurate with the adverse impact that loss, compromise or misuse of those BES Cyber Systems could have on the reliability of the BES. The concept of matching security controls with risk is common practice that is found in NIST and ISO guidelines for risk management. These best practices should be leveraged when considering the implementation of CIPv4 and the development of future standards such as CIP10 and CIP11 that will include requirements for medium and low risk BES Cyber Systems. In the draft release of CIP10, the Balancing Authority (BA), Reliability Coordinator (RC) and Transmission Operator (TOP) functions were listed separately and with additional qualifying criteria. This is a much better approach that is well aligned with best practices and future standard development. When considering the proposed CIPv4 criteria, the control centers for the Transmission Operator (TOP) function should only be included as Critical Assets if they operate transmission facilities that meet the critical asset |

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| | | | | bright line criteria listed in paragraph 1.6 (above 500kV) or 1.7 (300Kv or higher at stations interconnected at 300kV or higher with three or more other transmission stations). Not including these criteria will cause Non-Critical Assets to be identified as Critical Assets. In addition, the standards will go against established best practices and be in conflict with the already released draft of the CIP10 and CIP11 standards. Suggested change to Attachment 1 paragraph 1.14: Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Reliability Coordinator or Balancing Authority. Suggested change to Attachment 1 (Add paragraph 1.x): Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Transmission Operator for Transmission Facilities meeting the criteria in 1.6 or 1.7.<br>Requirement R2 Comments This section of R2 makes the requirement very confusing: For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes. If this is intended to be further clarification for generating units only, there should be a paragraph for this alone. In addition, the basis for “within 15 minutes” is not defined and could lead to subjectivity in the interpretation of this requirement. |

**Response**: Thank you for your comments.

The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues.

Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”

The requirement refers to shared cyber assets that can have a reliability impact on the group of generating units. This qualifier only includes Critical Assets identified in criterion 1.1. The 15-minute threshold is intended to include only those assets at generating units affecting real-time operations. This qualifier is particularly important to a generating plant because several systems (i.e. a fuel-handling system) may be essential

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| after a longer period of time but do not necessarily involve real-time reliability impact. We have updated the wording of R2 to clarify the meaning of this phrase. | | | | |
| William Price | M & A Electric Power Cooperative | 1 | Negative | Please review my submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Michelle Rheault | Manitoba Hydro | 1 | Negative | Please see comments submitted by Manitoba Hydro in the formal comment period. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Danny Dees | MEAG Power | 1 | Negative | MEAG supports the APPA's comments submitted to the NERC CIP standard drafting team. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Randi Woodward | Minnesota Power, Inc. | 1 | Negative | Please see comments submitted during the Comment Period. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Mark Ramsey | N.W. Electric Power Cooperative, Inc. | 1 | Negative | Please review submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Richard L. Koch | Nebraska Public Power District | 1 | Negative | NPPD agrees with and supports the comments provided by the American Public Power Association (APPA). |

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| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Kevin White | Northeast Missouri Electric Power Cooperative | 1 | Negative | Please review submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Robert Mattey | Ohio Valley Electric Corp. | 1 | Negative | Technical justification for "Bright line" criteria lacking. |
| **Response**: Thank you for your comments.<br><br>The SDT believes information provided in the posted guidance document provides sufficient technical justification for each criterion. | | | | |
| Brad Chase | Orlando Utilities Commission | 1 | Negative | SDT Proposed: 1.1 Each group of generating units (including nuclear generation) at a single plant location with an aggregate highest rated net Real Power capability of the preceding 12 months equal to or exceeding 1500 MW. APPA Comments: APPA and others commented on the CIP-010-1 standard as having arbitrary bright lines for generating units and requested that these bright line numbers have justification or have them based on the Contingency Reserve of each Reserve Sharing Group region. APPA commends the SDT for their attempted to come to agreement on a nationwide bright line for generating units based on an operationally significant threshold. The use of an average of the Contingency Reserve numbers from all the regions bases the bright-line on what the regions consider operationally significant. We understand that NERC standards are a minimum requirement and regions can look at their own operating criteria and determine if they need additional protection at lower Megawatt bright-lines. APPA is concerned that the use of the “Real Power Capability of the preceding 12 months” would bring in unnecessary volatility to applicability of this standard to certain groups of generating units. To alleviate this volatility we suggest that generation owners should use the facility ratings which are calculated and communicated under FAC-009-1 R2. R2. The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning |

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| | | | | Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities. SDT Proposed: 1.2. Each reactive resource or group of resources at a single location (excluding generation Facilities) having aggregate net Reactive Power nameplate rating of 1000 MVARs or greater. APPA Comments: APPA does not have a comment on criteria 1.2 at this time. SDT Proposed: 1.3. Each generation Facility that the Planning Coordinator or Transmission Planner designates as required for reliability purposes. APPA Comments: APPA commends the SDT on including the criteria in 1.3, which gives the PC and TP the ability to designate as critical any generating facilities for reliability purposes. This will cover critical units that are not captured within the bright line of criteria 1.1 without drawing in all units of a certain size that are not considered critical elsewhere on the system. APPA suggests that the designation of facilities be based on studies conducted under the TPL standards to justify the designation. Also, the use of NERC Glossary of term: "Adverse Reliability Impacts" will help clarify which units should be in this category. We are also concerned that the PC or TP will be looking at local vs. wide area reliability. There are some cases where the PC can designate Must Run units for temporary situations so this must be clarified within the criteria. APPA proposes the following rewording of criteria 1.3: "1.3 Each generation Facility that the Planning Coordinator or Transmission Planner designates as required to avoid BES Adverse Reliability Impacts for 1 year or longer." SDT Proposed: 1.4. Each Blackstart Resource identified in the Transmission Operator's restoration plan. APPA Comments: APPA is concerned that designating all Blackstart Resources as critical will divert limited resources to protect blackstart facilities that are only used to restore localized load. We believe it is the intent of the drafting team to identify the truly critical blackstart units (taking from the CIP-010-1 draft; only high impact facilities). APPA understands that criteria 1.4 uniformly identify all Blackstart Resources listed in the Transmission Operator's restoration plan as being Critical Assets with regards to the Bulk Electric System. Currently, many utilities include multiple Blackstart resources in the restoration plans provided to the Transmission Operator. Including numerous resources makes the plan much more robust and reliable as it provides additional well documented restoration options should unforeseen problems occur. As currently written, Item 1.4 inadvertently incentivizes utilities to remove blackstart resources from the restoration plan if these resources are not critical to an effective regional restoration plan, reducing the plan's overall |

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| | | | | effectiveness. Therefore, we believe there should be a threshold for Blackstart Resources, similar to nearly all other elements being considered in Attachment 1. This would allow utilities the freedom to include numerous resources in the Transmission Operators restoration plan without being swept into being identified as a critical asset. To implement this approach, we believe it is imperative to consider the Blackstart Resource's actual role in the restoration plan, not just its simple inclusion. For example, a 10 MW Blackstart Resource that directly supports restoration of a critical generating facility is much more important to the Bulk Electric System than a 10 MW Blackstart Resource that simply supplies local load during an outage. Therefore, APPA would propose judging the criticality of a Blackstart Resource by the relative importance of the generating unit(s) it directly supports. We would recommend rewording item 1.4 as follows, leveraging the existing language of criteria 1.15 and the capacity bright-line of criteria 1.13: 1.4 Each Blackstart Resource identified in the Transmission Operator's restoration plan, which meet either of the following criteria: 1.4.1 Used to directly start generation identified as a Critical Asset in criteria 1.1 or 1.3, 1.4.2 Used to directly start generation greater than an aggregate of 300 MW. We believe this approach should provide a better measure of a Blackstart Resource's potential impact on the Bulk Electric System, resulting in Critical Assets that adequately address system reliability in a practical manner. It also mitigates the likelihood that registered entities may decide to retire certain small blackstart units, thereby removing valuable but not critical blackstart resources from the Transmission Operator's restoration plan. We further support inclusion of "ALL Blackstart Resources" only when this standard is revised to provide for a tiered (High, Medium and Low) categorization of Critical Assets, such as the SDT's draft CIP-010-1 proposal.<br>SDT Proposed: 1.5. The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist. APPA Comments: APPA commends the SDT on differentiating between a single Cranking Path as a critical facility and multiple Cranking Paths as having redundancy in the BES and thus being less critical. Having this criteria stated in 1.5 incentivizes the entity to build in redundancy in infrastructure to lower criticality of a single asset. This truly does reward infrastructure reliability through a standard. APPA does request clarification of criteria 1.5: Where does this point of multiple paths lay in the electrical system? |

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>Does this include only the Generator Step-up Transformer, or does it include the whole substation where multiple transmission paths depart to a single generator? Also, APPA suggests that the SDT change “switching requirements” to “switching equipment.”<br>SDT Proposed: 1.6. Transmission Facilities operated at 500 kV or higher.<br>APPA Comments: APPA does not have a comment on criteria 1.6 at this time.<br>SDT Proposed: 1.7. Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. APPA Comments: APPA bel</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>Item 1.1 – The SDT notes your concern that the use of the “Real Power Capability of the preceding 12 months” would bring in unnecessary volatility to applicability of this standard to certain groups of generating units. The drafting team used time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities’ qualification against these bright-lines, the highest value was used. The 12-month time period was used so that seasonal ratings would not be an issue for generating plants that operate near the 1500 MW bright-line.<br><br>Item 1.3 – This criterion has been reworded to “Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.”<br><br>Item 1.4 – A Blackstart Resource is defined as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.” EOP-005-2 R1.4 states that the restoration plan must include “Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.” The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources.<br><br>Item 1.5 – The point where multiple paths exist in the Cranking Path is the step in the Transmission Operator’s restoration plan per EOP-005-2 R1.5, “Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started,” where the Transmission Operator can choose between the next Facilities on the BES to energize.</td></tr>
<tr><td>Richard J Kafka</td><td>Potomac Electric Power Co.</td><td>1</td><td>Negative</td><td>Pepco Holdings has submitted comments in the names of its affiliates, including Potomac Electric. Pepco would consider an affirmative vote if these issues are addressed.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. Please refer to the response to comments document.</td></tr>
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| Laurie Williams | Public Service Company of New Mexico | 1 | Negative | PNM Resources applauds the significant effort of the SDT in developing the revision to CIP-002-4, and conforming changes to CIP-003-4 through CIP-009-4. Although the most recent version of CIP-002-4 represents significant progress, PNM Resources must cast a negative vote with the following comments: The criteria related to blackstart resources do not consider the varying role of blackstart resources identified in restoration plans, and, as drafted, will require identification of any blackstart resource, or path, mentioned in a restoration plan to be identified as a Critical Asset. Entities in many regions may identify a significant number of Blackstart Resources in a restoration plan, representing primary and alternate resources allowing for a number of options for system restoration. PNM Resources recommends the following revisions to the criteria: 1.4. Each primary Blackstart Resource essential to the Transmission Operator's restoration plan. 1.5. The Facilities comprising the primary Cranking Paths and initial switching requirements from the primary Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist. |
| **Response**: Thank you for your comments.<br><br>Items 1.4 and 1.5 – The SDT considered using the word "primary," but ultimately rejected it as it is not a defined NERC Glossary term in this instance, nor is it used in EOP-005-2. A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." EOP-005-2 R1.4 states that the restoration plan must include "Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit." The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources. | | | | |
| Kenneth D. Brown | Public Service Electric and Gas Co. | 1 | Negative | Please see PSEG Companies' comments filed separately. The PSEG companies will change the vote to affirmative if the comments are adequately addressed by the drafting team. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Catherine Koch | Puget Sound Energy, Inc. | 1 | Negative | PSE supports this revision, however feels further clarity is necessary regarding Attachment 1, section 1.1, to recognize that a generation plant that is tripped as part of a Remedial Action Scheme (Special Protection System) in place to protect the Bulk Electric System should be exempted |

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| | | | | from Critical Asset designation. The inclusion of a generation plant in a RAS scheme infers that the plant is not critical to the operation of the BES. NERC included this same criteria in their guidance document "Security Guideline for the Electricity Sector: Identifying Critical Assets," page 10, table C-2. |
| **Response**: Thank you for your comments.<br><br>Criterion 1.1 is based on plant size. Criterion 1.12 stipulates Facilities related to SPSs and RASs. Both criteria should be used to determine whether a generation plant qualifies as a Critical Asset. | | | | |
| Tim Kelley | Sacramento Municipal Utility District | 1 | Negative | After reviewing the proposed version 4 language for CIP-002, R2, the placement of the additional text on generation is confusing. It appears to be trying to accomplish two different purposes. SMUD does not have any objections to the text itself, just the placement. SMUD proposes organizing the requirement as follows:<br>R2. Critical Cyber Asset Identification- Using the list of Critical Assets developed pursuant to Requirement R1, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. The Responsible Entity shall review this list at least annually, and update it as necessary. R2.1 For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics: R2.1.1 The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or, R2.1.2 The Cyber Asset uses a routable protocol within a control center; or, R2.1.3 The Cyber Asset is dial-up accessible. R2.2 For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1., the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes.<br>Additionally, SMUD, as a member of APPA, would like to reflect its support to those CIP-002-4 Standard comments submitted by APPA staff. |
| **Response**: Thank you for your comments. Please refer to the response to comments document for responses to APPA comments.<br><br>Requirement R2 has been changed to clarify the issues presented. | | | | |
| Robert Kondziolka | Salt River Project | 1 | Negative | SRP believes that a bright line assessment methodology for determining Critical Assets is not the best interest of reliability. This is especially true in the designation of substations and generating facilities. The attributes of these stations and their unique impact on Bulk Electric System reliability |

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| | | | | must be taken into account. There are several terms and phrases used within Requirement 2 of the proposed Standard that need to be better defined to eliminate ambiguity. These terms are: 1) essential to the operation of the Critical Asset, 2) adversely impact the reliable operation needs to be defined; and, 3) within 15 minutes. We believe the CIP-002-4 implementation plan for newly identified Critical Assets and associated Critical Cyber Assets provides inadequate time. SRP suggests the implementation timeframe be extended to 30 months after the effective date of the Standard. |
| **Response**: Thank you for your comments.<br><br>The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues.<br><br>The phraseology you are concerned about (annual) exists in the existing CIP-002-3 standard. The SDT expects this phraseology to be resolved in the next version<br><br>The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset. | | | | |
| Denise Stevens | Sho-Me Power Electric Cooperative | 1 | Negative | Please review submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Rich Salgo | Sierra Pacific Power Co. | 1 | Negative | This is a negative vote due solely to disagreement over some of the elements in Attachment 1 of the Standard. Overall, the draft Standard promotes the necessary clarity over which Assets shall be Critical. Detail comments have been provided via the official comment response form. In general, we believe that Attachment 1 is overly inclusive of elements and facilities that may have no material impact on BES reliability. In particular, we believe that not all blackstart resources should be treated identically - perhaps only the primary blackstart resource of a TOP's restoration plan should be identified; the designation of a facility as "required for reliability purposes" by a Planning entity needs more precision and clarification that this shoudl be limited to those facilities that have a perpetual reliability need, not an occasional one; 300kV and higher facilities ought not to be |

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| | | | | included unless they connect to four or more non-radial 300kV+ stations; and need further clarification of the distinction between generation control rooms and control centers. |
| **Response**: Thank you for your comments.<br><br>Item 1.4 – A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." The SDT feels that these units must be classified as Critical Assets. It should be noted that not all blackstart generators are Blackstart Resources.<br><br>Item 1.3 – This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."<br><br>Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Asset a Transmission Facility operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations.<br><br>Item 1.15 –This criterion has been changed to "Each control center or backup control center used to control generation at multiple plant locations, for any generation Facility or group of generation Facilities identified in criteria 1.1, 1.3, or 1.4. Each control center or backup control center used to control aggregate generation equal to or exceeding 1500 MWs in a single Interconnection." | | | | |
| Horace Stephen Williamson | Southern Company Services, Inc. | 1 | Negative | Comments were submitted via Comment Form: Project 2008-06 - Cyber Security 706 |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| William G. Hutchison | Southern Illinois Power Coop. | 1 | Negative | I realize that the politically correct want all BES assets to have some level of criticality, but the truth still remains that there are assets on the BES that are not critical to the operation of the BES. This is another prime example of creating compliance standards that only create documentation compliance and do not provide performance based standards. |
| **Response**: Thank you for your comments. The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. | | | | |

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| Larry Akens | Tennessee Valley Authority | 1 | Negative | Tennessee Valley Authority (TVA) appreciates the opportunity to comment on this CIP-002-4 draft. We fully support the standards development process and all the hard work and commitment by the drafting team members. For this draft, we have the following concerns which moved us to cast a Negative vote. Comments: Q1: Yes; no comment<br>Q2: 1.4. Each Blackstart Resource identified in the Transmission Operator's restoration plan. The language appears to require us to designate "Each" component in the System Restoration plan as CA. We currently include at least 2 paths for black start of every generation plant in the system, which would extend CA designation to a large number of components which otherwise would not be included by other criteria. The flexibility provided by our robust transmission infrastructure and large number black start capable plants serves to help ensure reliable operation of the BES, but designating as a CA each component that could participate in the total paths possible doesn't seem consistent with the intent of the standard. Recommendation: Revise language to allow entities to limit CA designation to those components participating in the primary black start path.<br>1.10. Transmission Facilities providing the generation interconnection required to directly connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3. There isn't a clear definition of the term "directly connected." Without this definition there are many way to interpret this requirement. Is this language meant to describe a facility where the substation is co-located with a generation facility? Also, does the language this mean total loss of substation or only partial? Recommendation: For the purpose of this standard revise language to clearly define "directly connected."<br>Q3: Yes; no comment Q4: Yes; no comment Q5: abstain Q6: abstain |

**Response**: Thank you for your comments.

Item 1.4 – The SDT considered using the word "primary," but ultimately rejected it as it is not a defined NERC Glossary term, nor is it used in EOP-005-2. A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." EOP-005-2 R1.4 states that the restoration plan must include "Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit." The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources.

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| Item 1.10 – The intent is to ensure the availability of Facilities necessary to support those generation Critical Assets. Any transmission Facility that, if lost, would result in the loss of a Critical Asset identified in criterion 1.1 or 1.3 would need to be classified as a Critical Asset. That might include the partial or total loss of a substation. | | | | |
| James W. Beck | Transmission Agency of Northern California | 1 | Negative | TANC hereby submits a negative vote on this ballot and refers the project drafting team to comments submitted by the American Public Power Association. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Jonathan Appelbaum | United Illuminating Co. | 1 | Negative | Concerns with CIP-002 V4 Attachemnt 1. Comment form submitted and concurrence with EEI comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Gregory L Pieper | Xcel Energy, Inc. | 1 | Negative | Please see our comments submitted during the concurrent comment period. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Venkataramakrishnan Vinnakota | BC Hydro | 2 | Negative | 1.7. Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations The present wording uses an arbitrary numbers of stations, the number of stations is immaterial BCH recommends the “Transmission Facilities operated at 300 kV or higher that if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs).<br>1.13. Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes. A clear definition of common control system(s) is required. Is under frequency or under voltage load shedding schemes considered control systems? The load shedding of 300 MW or more does it include firm or interruptible load or both?<br>1.16. Any additional assets that the Responsible Entity deems appropriate to include. To encourage reliability the additional assets deemed appropriate by a Responsible Entity should not be auditable. |

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| **Response**: Thank you for your comments.<br><br>Item 1.7 – In order to be more accurate in terms of the impact, the drafting team thought that it was more appropriate to refer to the number of connected transmission substations instead of using IROLs. The intent was to avoid double-circuit conditions and to include facilities that are actually more a part of the network than simple substations with double circuits between them. This includes upstream, downstream, radial and networked substations.<br><br>Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot. | | | | |
| Chuck B Manning | Electric Reliability Council of Texas, Inc. | 2 | Negative | ERCOT ISO has joined in the submission of the IRC SRC comments. Please see IRC SRC submission for details. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Kim Warren | Independent Electricity System Operator | 2 | Negative | We repeat the main reasons for our negative vote which are also stated in our comments on this project (submitted today). We do not agree with criteria 1.6 and 1.7 as written since some of the facilities identified as Critical Assets by applying them may have no impact on the BES. We therefore believe the list of relevant transmission facilities developed by the Responsible Entity, should be subject to an impact-based assessment by the Reliability Coordinator who has the wide-area view of the system. If necessary, an additional requirement that requires the RC to have a risk-based assessment methodology and to conduct the assessment should be included. We therefore propose the following specific wording: 1.6 Transmission facilities operated at 500 kV or higher, unless the annual review performed by the Reliability Coordinator (new requirement) demonstrates that destruction, degradation or unavailability of those assets will have no impact outside the local area and will not cause BES instability, separation, or cascading outages. 1.7 Transmission facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations, unless the annual review performed by the Reliability Coordinator (new requirement) demonstrates that destruction, degradation or unavailability of those assets will have no |

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| | | | | impact outside the local area and will not cause BES instability, separation, or cascading outages.<br>Additionally, we do not agree with the removal from the Applicability Section, of the exclusion that applies to facilities regulated by the Canadian Nuclear Safety Commission. This explicit statement makes it clear that CIP standards do not apply to those facilities which would not be the case if it were removed. |
| **Response**: Thank you for your comments.<br><br>Items 1.6 and 1.7 – You propose to add the criteria that the RC can determine through a risk-based evaluation that destruction, degradation or unavailability of certain assets will have no impact outside the local area and will not cause BES instability, separation, or cascading outages. The inclusion of a risk-based evaluation by any entity would not meet the objective of uniform application of Critical Asset identification across all entities.<br><br>The SDT is aware that the removal of the nuclear plant exclusion in response to a FERC order brought Canadian nuclear plants into the CIP standards. That was unintentional and will be corrected in the revised standards next posted for ballot. | | | | |
| Jason L Marshall | Midwest ISO, Inc. | 2 | Negative | We are concerned that criterion 1.3 in Attachment 1 of CIP-002-4 could be construed as transferring the responsibility for identifying Critical Assets from Generation Owners to the Planning Coordiantors. We oppose this and believe the obligation rests with the asset owner. Furthermore, paragraph 328 of Order 706 makes clear that the asset owner cannot transfer its responsibility for identifying Critical Assets to a third party. We suggest this criteria should be removed. Criteria 1.8, 1.9, and 1.12 should be modified because loss of facilities does not cause an IROL violation. An IROL includes a limit and a time constant Tv. In order for an IROL violation to occur, the limit must be exceeded for at least the time constant Tv. Tv is usually 30 minutes. Thus, when we consider the impact on the loss of facilities on an IROL, an operator will have enough time to adjust the system to prevent an IROL violation. For 1.8, the criterion should be modified to reflect that the facilities that comprise an IROL should be considered critical. The drafting team may also wish to consider loss of any facilities that set up the need for the IROL or cause the actual limit to change. For criterion 1.9, it is not clear why FACTs devices need to be singled out. Are they not covered in criterion 1.8 under Transmission Facilities? Inclusion of 1.9 is redundant and just causes confusion because it causes the reader to infer that the drafting team intended for them to be treated differently when in fact the criterion is the same as 1.8. For criterion 1.12, it would be more appropriate to assess the impact of an SPS, RAS, or automated switching system on the IROL. If loss of the SPS, |

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| | | | | RAS, or automated switching system causes an IROL to decrease, then the SPS, RAS, or automated switching system should be considered critical. |
| **Response**: Thank you for your comments.<br><br>Item 1.3 – The burden for identifying Critical Assets is still the Responsible Entity that is the asset owner. There is no burden or obligation placed on the Planning Coordinator or Transmission Planner to designate any unit as needed for reliability. This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."<br><br>Item 1.8 – This criterion has been changed to "Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."<br><br>Item 1.9 – FACTS devices were singled out to ensure that there was no confusion as to whether or not they were considered Critical Assets.<br><br>Item 1.9 – This criterion has been changed to "Flexible AC Transmission Systems (FACTS), at a single station or substation location, that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."<br><br>Item 1.12 – This criterion has been changed to "Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limit (IROL) violations for failure to operate as designed." | | | | |
| Richard J. Mandes | Alabama Power Company | 3 | Negative | Comments were submitted via Comment Form: Project 2008-06 - Cyber Security 706 |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Raj Rana | American Electric Power | 3 | Negative | Overall, AEP is supportive of the efforts and the general concepts of this draft; however, there are a few refinements that will enhance the requirements and remove ambiguity. AEP encourages the SDT to consider the items below in a future draft of the standard: AEP would contend that there are regional differences that would be relevant to determine a MW threshold for generators. We support the concept that was contained in the last draft that made the determination based on the capacity reserves. However, the prior language would need to be revisited to ensure that value was fixed for a period of time. In addition, requirement 2.2 uses the term control center (also used in attachment 1) that is not a NERC defined |

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| | | | | term. This will introduce ambiguity to implementation. There has been ongoing confusion regarding the difference between "control centers" and "control rooms." We do not believe that a "control room" at a power plant or a substation would be considered a "control center." There is language in the NERC Security Guideline for Electricity Sector: Identifying Critical Assets document that the SDT should consider and incorporate into the NERC Glossary. Net real power capability testing is defined in MOD-024 standards that have yet to be FERC approved. Furthermore, not all of the regions have defined the parameters for the capability testing. |
| **Response**: Thank you for your comments.<br><br>Item 1.1 - The issue with using different MW values in each region is that it does not meet the objective of uniform application of Critical Asset identification across all entities.<br><br>At this time, the SDT is choosing not to add "control center" to the NERC Glossary. We feel defining this term under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. This term is used in other approved NERC standards already in effect.<br><br>CIP-002-4 does not require net real power capability testing. | | | | |
| Nathan Mitchell | American Public Power Association | 3 | Negative | See APPA CIP-002-4 Task Force Comments |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Chris W Bolick | Associated Electric Cooperative, Inc. | 3 | Negative | Please review submitted comments |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Pat G. Harrington | BC Hydro and Power Authority | 3 | Negative | Critical Assets List comments 1.7. Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations The present wording uses an arbitrary numbers of stations, the number of stations is immaterial BCH recommends the "Transmission Facilities operated at 300 kV or higher that if destroyed, degraded, misused or otherwise rendered unavailable, violate |

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| | | | | one or more Interconnection Reliability Operating Limits (IROLs). 1.13. Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes. A clear definition of common control system(s) is required. Is under frequency or under voltage load shedding schemes considered control systems? The load shedding of 300 MW or more does it include firm or interruptible load or both? 1.16. Any additional assets that the Responsible Entity deems appropriate to include. To encourage reliability the additional assets deemed appropriate by a Responsible Entity should not be auditable. |
| **Response**: Thank you for your comments.<br><br>Item 1.7 – In order to be more accurate in terms of the impact, the drafting team thought that it was more appropriate to refer to the number of connected transmission substations instead of using IROLs. The intent was to avoid double-circuit conditions and to include facilities that are actually more a part of the network than simple substations with double circuits between them. This includes upstream, downstream, radial and networked substations.<br><br>Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot. | | | | |
| Rebecca Berdahl | Bonneville Power Administration | 3 | Negative | Please refer to BPA comments submitted during the formal comment period on 10/26/10 |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Ralph J Schulte | Central Electric Power Cooperative | 3 | Negative | Please review submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Steve Alexanderson | Central Lincoln PUD | 3 | Negative | Please see comments posted by Steve Alexanderson at Central Lincoln. |

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| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Linda R. Jacobson | City of Farmington | 3 | Negative | FEUS agrees with APPA's comments and proposed changes. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Gregg R Griffin | City of Green Cove Springs | 3 | Negative | FMPA commends the SDT on making significant headway on the version 4 standards. However, there are significant additional improvement that should be made to make the criteria of Attachment 1 less arbitrary and that truly measures those assets that can have an Adverse Reliability Impact. Also, the standard is still unclear in several areas, such as how to identify CCAs at a substation if a substation is determined to be a CA that needs to be clarified. Please see FMPA's comments submitted through the formal comment process for more specific detail and proposed alternatives. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Roger Powers | City Water, Light & Power of Springfield | 3 | Negative | While the "bright line" approach satisfies the FERC requirement for ERO guidance in the development of Risk-based Methodology, it does not allow for the flexibility to consider each responsible entity's individual circumstances as suggested in Paragragh 253 of FERC Order 706. It is not clear that a risk assessment was used to develop the "bright lines" contained in the standard. |
| **Response**: Thank you for your comments. Regarding the directives for external review and guidance in the FERC Order, the SDT believes the criteria in Attachment 1 are in response to FERC Order 706 paragraph 329. In consideration of this directive, the SDT decided there did not exist across all regions an appropriate third party to provide this type of oversight. Also, external review and oversight carries with it the compliance overhead and arbitration processes analogous to the TFE process. This "bright-line" approach removes the variability of entity defined methodologies that would prompt the need for external review. | | | | |
| Russell A Noble | Cowlitz County PUD | 3 | Negative | Please refer to APPA's and my comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |

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| Michael F Gildea | Dominion Resources Services | 3 | Negative | Dominion conceptually supports bright line criteria for determining critical assets. However, we cannot vote in favor at this time because we believe that changes are needed in Table 2 that recognize the implementation for infrastructure (physical and electronic security) should be equal to, or longer than, that required for training. We also believe that the bright line criteria for generation control center needs further effort. Please see more specific comments/recommendation submitted by Dominion. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Anthony L Wilson | Georgia Power Company | 3 | Negative | Comments were submitted via Comment Form: Project 2008-06 - Cyber Security 706 |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Gwen S Frazier | Gulf Power Company | 3 | Negative | Comments were submitted via Comment Form: Project 2008-06 - Cyber Security 706 |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| David L Kiguel | Hydro One Networks, Inc. | 3 | Negative | Hydro One is casting a negative vote for the following reasons:<br>1. We do not believe the standard will result in an improvement in reliability since the revisions merely replace the risk-based assessment methodology with a list of criteria that will ultimately result in inclusion of facilities on the Critical Assets list that are non-impactive on the BES.<br>2. We do not agree with criteria 1.6 and 1.7 in Attachment 1 as written. Application of these criteria would result in the inclusion of facilities that will have no impact on the BES reliability. We believe that the list of applicable facilities should be determined following an impact-based assessment to be performed by the Reliability Coordinator. If necessary, an additional requirement that requires the RC to have a risk-based assessment methodology and to conduct/review the assessment should be included. We therefore propose the following wording to replace 1.6 and 1.7 in Attachment 1: 1.6 Transmission facilities operated at 500 kV or higher, unless the annual review performed by the RC determines that destruction, degradation or unavailability of those assets will have no |

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<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>impact outside the local area and will not cause BES instability, separation, or cascading outages. 1.7 Transmission Facilities operated at 300 kV or higher to less than 500 kV at stations interconnected at 300 kV or higher with three or more other transmission stations, unless the annual review performed by the RC determines that destruction, degradation or unavailability of those assets will not have impact outside the local area and will not cause BES instability, separation, or cascading outages.<br>3. We do not agree with the removal of the exclusion that applies to facilities regulated by the Canadian Nuclear Safety Commission from the Applicability Section, This explicit statement makes it clear that CIP standards do not apply to those facilities which would not be the case if it were removed.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>1) The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology.<br>2) Items 1.6 and 1.7 – The SDT does not feel that a power flow analysis (impact-based or risk-based) may lead to a consistent application of the criteria, due to the numerous factors which can impact substation power flows. Such a study would need to be rigorously defined for the industry. We thank you for your proposal and will take it under consideration for future revisions.<br>3) The SDT is aware that the removal of the nuclear plant exclusion in response to a FERC order brought Canadian nuclear plants into the CIP standards. That was unintentional and will be corrected in the revised standards next posted for ballot.</td></tr>
<tr><td>Theodore J Hilmes</td><td>KAMO Electric Cooperative</td><td>3</td><td>Negative</td><td>please review submitted comments</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. Please refer to the response to comments document.</td></tr>
<tr><td>Gregory David Woessner</td><td>Kissimmee Utility Authority</td><td>3</td><td>Negative</td><td>KUA commends the SDT on making significant headway on the version 4 standards. However, there are significant additional improvement that should be made to make the criteria of Attachment 1 less arbitrary and that truly measures those assets that can have an Adverse Reliability Impact. Also, the standard is still unclear in several areas, such as how to identify CCAs at a substation if a substation is determined to be a CA. That needs to be clarified. Please see FMPA's comments submitted through the formal comment process for more specific detail and proposed alternatives on KUA's views.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. Please refer to the response to comments document.</td></tr>
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| Stephen D Pogue | M & A Electric Power Cooperative | 3 | Negative | Please review submitted comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Darl Shimko | Madison Gas and Electric Co. | 3 | Negative | The comments, below, are issues that the SDT should address before the next ballot. Q1 through Q6 refer to questions in the Unofficial Comment Form for Project 2008-06.<br>Q1: We do not believe the proposed standard will lead to an improvement in reliability in all cases. If a bright line is used, it removes all engineering analysis the entity is currently performing with the current CIP-002-3 methodology. This may bring in or remove assets for this Standard. A bright-line approach may be useful to a smaller entity, but may not be in the best interest to larger entities. The SDT should consider a bright line with a MW threshold for physical unit size or MW loads for control centers, see comments below.<br>Q2: Suggested improvements to Attachment 1: Criterion Number 1.5 -- Based on the Rationale Document, please clarify that Facilities within the Cranking Paths will be assigned the Critical Asset identification up to the point where multiple path options exist. Criterion Number 1.13 -- Based on the Rationale Document, please clarify that the 300 MW level applies to a single common control system and not multiple like systems such as those installed for UFLS protection (multiple identical or similar individual, but independent, relays that may shed 300 MW's or more in aggregate, but individually shed less than 300 MW). Criterion Number 1.14 -- Based on the Rationale Document, every RC, BA, and TOP's control center, control system, backup control center and backup control system is Critical due to EOP-008. EOP-008-0 is the FERC approved Standard for US entities. We note the purpose of EOP-008-0 is: "Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable". Furthermore, the SDT quoted EOP-008-1 in the Rational Document, which is not FERC approved. The SDT needs to consider this when writing a continental wide Standard. The phrase in the Rationale Document, "While it is clear that the primary and all backup control centers operated by RCs, BAs, and TOPs must be designated as Critical Assets", is unjustified. Assuming a BA controls no critical assets qualified as such by other criteria, a BA that, in aggregate, controls relatively small amounts of |

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| | | | | real and/or reactive power clearly has less of an effect on reliability than a BA that controls relatively large amounts of such resources. Indeed, the fact that "size matters" is recognized by Criteria 1.1, 1.2, 1.6, 1.7, 1.13, and 1.15. Criterion 1.14 should be modified to recognize this conclusion by including relevant quantitative thresholds. Thresholds that were proposed in CIP-010 Criteria 1.13 and 1.14 would be reasonable. In any event, the thresholds for the BA control center or control system should be no more inclusive than those used to qualify the individual assets controlled by the BA. To complicate matters, presently there are 28 Local Balancing Authorities (LBA's) that are part of the Midwest ISO BA Area (JRO00001). These entities do not perform all the BA functional obligations as stated in the Rationale Document (the MISO BA performs the majority of BAL-001 through BAL-005). Furthermore, the scopes of operation of the LBA's span a wide range from small to large and few too many resources. This underscores the need to not assume that any BA (or LBA) that performs or supports any BA function or part of a BA function is necessarily critical to BES reliability. Please provide the analysis and justification to how these entities fit into the BA requirement as stated in 1.14. If it is the intent of the SDT to capture the generation within the balancing functions of a BA, the SDT has that covered by Criteria 1.15.<br>Q3: While we agree with the general requirement of R1, we do not agree with certain aspects of Attachment 1 - Critical Asset Criteria, as discussed in previous comments, above.<br>Q4: We agree with R2.<br>Q5: The implementation plan is clear and reasonable regarding entities that either in the past have identified they have CA's, or have never identified CA's. However, there is an issue when an entity has previously identified one type of asset as critical and then later identifies another type of critical asset. For example, a control center was previously identified as being a CA. Later, the entity identifies a cranking path or Blackstart generator as being a CA. It is recommended that if an asset dissimilar to previously identified critical assets is identified as a CA, that the entity is given 24 months to become compliant. This time is needed since the entity is now in an area that they may have not dealt with in the past.<br>Q6: The implementation plan for newly identified CCAs should allow 24 months to become compliant when the newly identified CCAs are associated with newly identified critical assets of a type that was not previously identified as critical. See Comment Q5, above. |

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| **Response**: Thank you for your comments.<br><br>Q1: The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology throughout North America.<br><br>Q2: Item 1.5 – The point where multiple paths exist in the Cranking Path is the step in the Transmission Operator's restoration plan per EOP-005-2 R1.5, "Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started," where the Transmission Operator can choose between the next Facilities on the BES to energize.<br><br>Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator."  A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12."  A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13.  Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."  It is appropriate to refer to an industry-approved and NERC BOT-approved standard in a guidance document, even if it has not been accepted at FERC.<br><br>Q3: Please refer to response to Q2 above.<br><br>Q4: Thank you.<br><br>Q5: The SDT believes there is precedent showing this implementation period is reasonable.  Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets.  This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset.<br><br>Q6: The SDT believes there is precedent showing this implementation period is reasonable.  Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets.  This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset. | | | | |
| Greg C. Parent | Manitoba Hydro | 3 | Negative | Please see comments submitted by Manitoba Hydro in the formal comment period. |
| **Response**:Thank you for your comments.  Please refer to the response to comments document. | | | | |

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<tr><td>Don Horsley</td><td>Mississippi Power</td><td>3</td><td>Negative</td><td>Comments were submitted via Comment Form: Project 2008-06 - Cyber Security 706</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. Please refer to the response to comments document.</td></tr>
<tr><td>Steven M. Jackson</td><td>Municipal Electric Authority of Georgia</td><td>3</td><td>Negative</td><td>MEAG supports the APPA's comments submitted to the NERC CIP standard drafting team.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. Please refer to the response to comments document.</td></tr>
<tr><td>John S Bos</td><td>Muscatine Power & Water</td><td>3</td><td>Negative</td><td>Just because a Balancing Authority or Transmission Operator has a control center or back-up control center should not automatically cast those control centers as Critical Assets. A BA or TOP with a small system (very small native system load, generation, and very minor transmission system) should not be forced into the CIP compliance world just because they have control centers. This is an incredible expense for a small utility. If control centers are to be determining factors for inclusion of a small BA or TOP under CIP-002 V4, there should be criteria developed based on the size of the utility. For instance, a BA or TOP with control centers serving a native system of greater than X MW would be considered for inclusion. Or a BA or TOP with control centers and a transmission system of greater than X miles would be considered for inclusion. Or a BA or TOP with control centers and greater than X MW of generation on their system would be considered for inclusion. Forcing small vertically-integrated utilities with exceedingly minor impact on the BES into the CIP compliance world is not equitable.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”</td></tr>
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| Tony Eddleman | Nebraska Public Power District | 3 | Negative | NPPD comments are addressed by comments submitted through the American Public Power Association (APPA). We agree with and support the APPA comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Skyler Wiegmann | Northeast Missouri Electric Power Cooperative | 3 | Negative | Please review submitted comments |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Rick Keetch | NRG Energy Power Marketing, Inc. | 3 | Negative | Pertaining to CIP-002-4 R1, the following need to be addressed in Attachment 1:<br>1.1 - Add capacity factor as a qualifier for exclusion below an established low threshold.<br>1.3 - Mandate coordination/approval process between the Transmission Planner and entity that have been designated critical by the Transmission Planner. These classifications and approvals need to take into consideration 5 year forecasts for planning and budgeting purposes..<br>1.5 - TOP needs to define the cranking path in restoration plan to the affected entities to adequately secure these restoration paths..<br>1.9 - Please explain FACTS - need definition<br>1.10 - Need coordination between TOP & GO to identify critical assets.<br>1.15 - How is the 1500 MW aggregate determined? Is it an aggregate of generator name plates or the sum of controllable megawatts between a unit's high and low limits?<br>General: Attachment 1 needs to have defined terms for capability, plant, control center<br>Requirement 2 needs to clarify the following items: 1) Need Clarification on routable path, discrete links and serial connections as it pertains to CIP-002-3 R3: Is a device considered to communicate outside the ESP using routable protocol if ANY portion of the communications path uses routable protocol?<br>2)Need clarification concerning shared assets. Does it mean shared between a single device or same device on a network?<br>3)R2 states that only shared cyber assets for a group of generating units at |

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| | | | | a single location identified in Attachment 1 criteria 1.1, namely the 1500 MWs brightline, that could impact reliable operation, should be considered. Does this cyber asset identification only include assets meeting criteria 1.1 and therefore exclude any cyber assets utilized for reliable operation of a designated critical asset such as a single blackstart resource? Please provide clarification in this requirement. |
| **Response**: Thank you for your comments.<br><br>Item 1.1 – The SDT debated whether to include capacity factor in this criterion. The reason we ultimately chose not to include capacity factor is twofold. First, there is no consistent method to select an appropriate capacity factor, and low capacity factor units may be critical to the system at peak load conditions. Second, there was concern that some units might fall below the line during major outage periods, taking them off the Critical Asset list one year and putting them back on the list the next year.<br><br>Item 1.3 –This criterion has been reworded to, “Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.”<br><br>Item 1.5 – Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in EOP-005-2 to “provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan.”<br><br>Item 1.9 – FACTS is defined by IEEE as “Alternating Current Transmission Systems incorporating power electronics-based and other static controllers to enhance controllability and power transfer capability.”<br><br>Item 1.10 – The assets would be identified by the asset owners. It is agreed that communication between GOs and TO/TOPs will be required.<br><br>Item 1.15 – This is the aggregate highest rated net Real Power capability output of all generation under dispatch/control.<br><br>At this time, the SDT is choosing not to add “capability,” “plant,” or “control center” to the NERC Glossary. We feel defining these terms under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. These terms are used in other approved NERC standards already in effect.<br><br>The requirement refers to shared cyber assets that can have a reliability impact on the group of generating units. This qualifier only includes Critical Assets identified in criterion 1.1. | | | | |
| David McDowell | NW Electric Power Cooperative, Inc. | 3 | Negative | Please review submitted comments. |

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| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Ballard Keith Mutters | Orlando Utilities Commission | 3 | Negative | See comments submitted on behalf or Orlando Utilities Commission. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Richard H. Chapman | Owensboro Municipal Utilities | 3 | Negative | There is too much ambiguity in Attachment 1 1.14, the Critical Control Center definition needs further clarification controlling either a specified load or specified voltage level. |
| **Response**: Thank you for your comment.<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, also has been added which states, " Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection." | | | | |
| Michael Mertz | PNM Resources | 3 | Negative | PNM Resources applauds the significant effort of the SDT in developing the revision to CIP-002-4, and conforming changes to CIP-003-4 through CIP-009-4. Although the most recent version of CIP-002-4 represents significant progress, PNM Resources must cast a negative vote with the following comments:<br>The criteria related to blackstart resources do not consider the varying role of blackstart resources identified in restoration plans, and as drafted, will require identification of any blackstart resource, or path, mentioned in a restoration plan to be identified as a Critical Asset. Entities in many regions may identify a significant number of Blackstart Resources in a restoration plan, representing primary and alternate resources allowing for a number of options for system restoration. PNM Resources recommends the following revisions to the criteria: 1.4. Each primary Blackstart Resource essential to the Transmission Operator's restoration plan. 1.5. The Facilities comprising the primary Cranking Paths and initial switching requirements from the primary Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on |

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>the Cranking Path where multiple path options exist.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>Items 1.4 and 1.5 – The SDT considered using the word “primary,” but ultimately rejected it as it is not a defined NERC Glossary term in this instance, nor is it used in EOP-005-2. A Blackstart Resource is defined as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.” EOP-005-2 R1.4 states that the restoration plan must include “Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.” The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources.</td></tr>
<tr><td>Jeffrey Mueller</td><td>Public Service Electric and Gas Co.</td><td>3</td><td>Negative</td><td>Please see PSEG Companies' comments filed separately. The PSEG companies will change the vote to affirmative if the comments are adequately addressed by the drafting team.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. Please refer to the response to comments document.</td></tr>
<tr><td>James Leigh-Kendall</td><td>Sacramento Municipal Utility District</td><td>3</td><td>Negative</td><td>After reviewing the proposed version 4 language for CIP-002, R2, the placement of the additional text on generation is confusing. It appears to be trying to accomplish two different purposes. SMUD does not have any objections to the text itself, just the placement. SMUD proposes organizing the requirement as follows: R2. Critical Cyber Asset Identification- Using the list of Critical Assets developed pursuant to Requirement R1, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. The Responsible Entity shall review this list at least annually, and update it as necessary. R2.1 For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics: R2.1.1 The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or, R2.1.2 The Cyber Asset uses a routable protocol within a control center; or, R2.1.3 The Cyber Asset is dial-up accessible. R2.2 For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1., the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes. Additionally, SMUD, as a member of APPA, would like to reflect its support</td></tr>
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| | | | | to those CIP-002-4 Standard comments submitted by APPA staff. |
| **Response**: Thank you for your comments. Please refer to the response to comments document for responses to APPA comments.<br><br>Requirement R2 has been changed to clarify the issues presented. | | | | |
| John T. Underhill | Salt River Project | 3 | Negative | SRP believes that a bright line assessment methodology for determining Critical Assets is not in the best interest of reliability. This is especially true in the designation of substations and generating facilities. The attributes of these stations and their unique impact on Bulk Electric System reliability must be taken into account. There are several terms and phrases used within Requirement 2 of the proposed Standard that need to be better defined to eliminate ambiguity. These terms are: 1) essential to the operation of the Critical Asset, 2) adversely impact the reliable operation needs to be defined; and, 3) within 15 minutes. We believe the CIP-002-4 implementation plan for newly identified Critical Assets and associated Critical Cyber Assets provides inadequate time. SRP suggests the implementation timeframe be extended to 30 months after the effective date of the Standard. |
| **Response**: Thank you for your comments.<br><br>The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues.<br><br>The phraseology you are concerned about (annual) exists in the existing CIP-002-3 standard. The SDT expects this phraseology to be resolved in the next version<br><br>Thank you for your comment. The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset. | | | | |
| Scott Peterson | San Diego Gas & Electric | 3 | Negative | SDG&E has submitted suggested changes that it feels should be incorporated before it can vote in favor of the revision. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Jeff L Neas | Sho-Me Power Electric | 3 | Negative | Please review submitted comments. |

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| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| James R. Keller | Wisconsin Electric Power Marketing | 3 | Negative | 1. When reviewing the mapping document posted with the proposed CIP-002-4 standard, do you believe that the proposed standard will lead to an improvement in reliability when compared to the standard it proposes to replace? 1 Yes 0 No Comments: We understand that the errata, which removes discussion of the “risk-based assessment methodology” from the proposed CIP-002-4 standard, would also apply to the mapping document. We appreciate the bright-line clarification to ensure consistent identification of Critical Assets throughout the industry.<br>2. CIP-002-4 Attachment 1 contains criteria that define elements that must be classified as Critical Assets. Do you have any suggestions that would improve the proposed criteria? If so, please explain and provide specific suggestions for improvement. 1 Yes 0 No Comments: We suggest that the functional entities Planning Coordinator and Transmission planner be added to the applicability section. Feedback on specific criteria as follows:<br>1.1, We request clarification on the phrase “single plant location”. This phrase is not defined and it is not clear what level of proximity of generators would be considered a “single plant location”. Rather than discuss this in terms of geography (location), we feel it would be better to discuss in terms of “Each group of generating units (including nuclear generation), operated using common cyber control systems other than the Control Centers identified in 1.14 and 1.15, with an aggregate…”.<br>1.3, We suggest the wording: “Each generation facility designated by the Planning Coordinator or Transmission Planner as required to avoid one or more reliability criteria violations”.<br>1.4, The blackstart units deemed critical should be only those identified by the Transmission Operator to meet the minimum critical blackstart requirement. The resulting suggested wording would be: “Each Blackstart Resource identified in the Transmission Operator’s restoration plan required to meet the minimum critical blackstart requirement”.<br>1.8, We suggest the wording: “Transmission Facilities at a single location that the Planning Coordinator or Transmission planner has designated that, if destroyed, degraded, misused or otherwise rendered unavailable, would result in one or more Interconnection Reliability Operating Limit (IROL) |

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| | | | | violations". 1.9, We suggest similar wording: "...unavailable, would result in one or more Interconnection Reliability Operating Limit (IROL) violations". 1.11, We suggest the following wording: "Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements". 1.12, We suggest the following wording: "...unavailable, would cause one or more Interconnection Reliability Operating Limit (IROL) violations for failure to operate as designed". 1.14, We suggest this be made consistent with 1.15, i.e. "Each control center, or backup control center, used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator". 1.16, We suggest the following wording: "Any additional assets owned by the Responsible Entity that the Responsible Entity deems appropriate to include". 3. Requirement R1 of draft CIP-002-4 states, "Critical Asset Identification - Each Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the criteria contained in CIP-002-4 Attachment 1 - Critical Asset Criteria. The Responsible Entity shall review this list at least annually, and update it as necessary." Do you agree with the proposed Requirement R1? If not, please explain why and provide specific suggestions for improvement. 1 Agree 0 Disagree Comments: 4. Requirement R2 of draft CIP-002-4 states, "Using the list of Critical Assets developed pursuant to Requirement R1, each Responsible Entity shall develop a list of associated Critical Cyber Assets performing a function essential to the operation of the Critical Asset. For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes. Each Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics". The requirement then lists characteristics using the same text that is contained in the existing CIP-002-3 R3. Do you agree with the proposed Requirement R2? If not, please explain why and provide specific suggestions for improvement. 1 Agree 0 Disagree Comments: Although we agree with the |

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| | | | | proposed Requirement R2, We are concerned that the document "CIP-002-4 Cyber Security - Critical Cyber Asset Identification: Rationale and Implementation Reference Document" actually appears to provide more rationale and guidance on Critical Assets than Critical Cyber Assets. 5. Do you agree with the proposed implementation plan for the Version 4 standards? If not, please explain and provide specific suggestions for improvement. 1 Yes 0 No Comments: 6. Do you agree with the proposed revisions to the implementation plan for newly identified CCAs and Responsible Entities? If not, please explain and provide specific suggestions for improvement. 0 Yes 1 No Comments: We believe that it would be better to simply have a uniform 18 month implementation deadline for newly identified CCAs rather than have different timelines for different requirements. This will simplify reporting and streamline efforts to become fully compliant. We understand that nuclear timelines are subject to NRC requirements and the necessity of accomplishing some tasks only during refueling outages appropriately dictates a separate schedule for them. |

**Response**: Thank you for your comments.

Q2. Since there is no Requirement that applies to the Planning Coordinator or the Transmission Planner, it is not appropriate to include them in the Applicability section.

Item 1.1 – The guidance document posted by the SDT provides direction on the location issue. "Single plant location" refers to a group of generating units occupying a defined physical footprint and designated as an individual "plant" using commonly accepted generating facility terminology. Adjacent plants would be defined using the same criteria. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant.

Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."

Item 1.4 – A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." The SDT feels that these units must be classified as Critical Assets. It should be noted that not all blackstart generators are Blackstart Resources.

Item 1.8 – According to FAC-014-2, IROLs are established by Transmission Operators, Transmission Planners, and Planning Authorities. The Reliability Coordinator ensures that IROLs are established and are consistent with its methodology. This criterion has been changed to "Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or

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| Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."<br><br>Item 1.9 – This criterion has been changed to "Flexible AC Transmission Systems (FACTS), at a single station or substation location, that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2 "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." It is not limited to offsite power requirements.<br><br>Item 1.12 – This criterion has been changed to "Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limit (IROL) violations for failure to operate as designed."<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot.<br><br>Q4. Thank you for your comments. The SDT will reexamine the guidance document.<br><br>Q5. Due to the limited scope of version 4, the SDT is only making conforming changes to the Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities. | | | | |
| Allen Mosher | American Public Power Association | 4 | Negative | See group comments submitted by the APPA CIP Task Force. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Shamus J Gamache | Central Lincoln PUD | 4 | Negative | Please see comments posted by Steve Alexanderson at Central Lincoln. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |

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| David Frank Ronk | Consumers Energy | 4 | Negative | In Criteria 1.4, we would prefer to see Blackstart Resources for primary paths only specified. The way it is written, all Blackstart Resources, including those for alternate paths, would be included. This creates ambiguity as there are very many possible alternate cranking paths.<br>We dislike Criteria 1.5 and the wording in the Rationale Document. Similar to 1.4, the words "primary path" are no longer used and depending on interpretation, additional resources on what are now alternate cranking paths could be brought into play. The Standard should be clear and not subject to interpretation. |
| **Response**: Thank you for your comments.<br><br>Items 1.4 and 1.5 – The SDT considered using the word "primary", but ultimately rejected it as it is not a defined NERC Glossary term in this instance, nor is it used in EOP-005-2. A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." EOP-005-2 R1.4 states that the restoration plan must include "Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit." The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources. | | | | |
| Rick Syring | Cowlitz County PUD | 4 | Negative | The Attachment will wrongfully include some assets as critical. Please refer to Cowlitz County PUD comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Frank Gaffney | Florida Municipal Power Agency | 4 | Negative | FMPA commends the SDT on making significant headway on the version 4 standards. However, there are significant additional improvement that should be made to make the criteria of Attachment 1 less arbitrary and that truly measures those assets that can have an Adverse Reliability Impact. Also, the standard is still unclear in several areas, such as how to identify CCAs at a substation if a substation is determined to be a CA that needs to be clarified. Please see FMPA's comments submitted through the formal comment process for more specific detail and proposed alternatives. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |

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| Thomas W. Richards | Fort Pierce Utilities Authority | 4 | Negative | FPUA commends the SDT on making significant headway on the version 4 standards. However, there are significant additional improvement that should be made to make the criteria of Attachment 1 less arbitrary and that truly measures those assets that can have an Adverse Reliability Impact. Also, the standard is still unclear in several areas, such as how to identify CCAs at a substation if a substation is determined to be a CA that needs to be clarified. Please see FMPA's group comments submitted on our behalf through the formal comment process for more specific detail and proposed alternatives. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Bob C. Thomas | Illinois Municipal Electric Agency | 4 | Negative | IMEA appreciates the SDT's efforts to simplify CIP-002. IMEA believes it will be in a position to affirm this proposed Reliability Standard revision after comments on Draft 1 and comments during balloting are addressed. IMEA supports comments submitted by the American Public Power Association. In addition, as IMEA commented, we recommend Criterion 1.8 be continued with the following language: "...(IROLs) as demonstrated by the Reliability Coordinator." If the RC is not appropriate, it will be necessary to add the appropriate functional entity, for demonstrating IROLs, to Applicability Secion 1.4. This addional language will clarify that the TO, LSE, etc. is not responsible for demonstrating IROLs. |
| **Response**: Thank you for your comments. Please refer to the response to comments document for responses to APPA's comments.<br><br>Item 1.8 – According to FAC-014-2, IROLs are established by Transmission Operators, Transmission Planners, and Planning Authorities The Reliability Coordinator ensures that IROLs are established and are consistent with its methodology. This criterion has been changed to "Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies." | | | | |
| Christopher Plante | Integrys Energy Group, Inc. | 4 | Negative | We believe that a bright line criteria as proposed by the ballot will improve the reliability and safety of the BES. However, changes as provided by MRO's NSRS need to be incorporated into the proposed standard to eliminate the potential for arbitrary application and capricious enforcement of the standard. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Richard Comeaux | LaGen | 4 | Negative | Pertaining to CIP-002-4 R1, the following need to be addressed in Attachment 1: |

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| | | | | 1.1 - Add capacity factor as a qualifier for exclusion below an established low threshold.<br>1.3 - Mandate coordination/approval process between the Transmission Planner and entity that have been designated critical by the Transmission Planner. These classifications and approvals need to take into consideration 5 year forecasts for planning and budgeting purposes..<br>1.5 - TOP needs to define the cranking path in restoration plan to the affected entities to adequately secure these restoration paths..<br>1.9 - Please explain FACTS - need definition<br>1.10 - Need coordination between TOP & GO to identify critical assets.<br>1.15 - How is the 1500 MW aggregate determined? Is it an aggregate of generator name plates or the sum of controllable megawatts between a unit's high and low limits?<br>General: Attachment 1 needs to have defined terms for capability, plant, control center<br>Requirement 2 needs to clarify the following items:<br>1) Need Clarification on routable path, discrete links and serial connections as it pertains to CIP-002-3 R3: Is a device considered to communicate outside the ESP using routable protocol if ANY portion of the communications path uses routable protocol?<br>2)Need clarification concerning shared assets. Does it mean shared between a single device or same device on a network?<br>3)R2 states that only shared cyber assets for a group of generating units at a single location identified in Attachment 1 criteria 1.1, namely the 1500 MWs brightline, that could impact reliable operation, should be considered. Does this cyber asset identification only include assets meeting criteria 1.1 and therefore exclude any cyber assets utilized for reliable operation of a designated critical asset such as a single blackstart resource? Please provide clarification in this requirement. |

**Response**: Thank you for your comments.

Item 1.1 – The SDT debated whether to include capacity factor in this criterion. The reason we ultimately chose not to include capacity factor is twofold. First, there is no consistent method to select an appropriate capacity factor, and low capacity factor units may be critical to the system at peak load conditions. Second, there was concern that some units might fall below the line during major outage periods, taking them off the Critical Asset list one year and putting them back on the list the next year.

Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."

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| Item 1.5 – Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."<br><br>Item 1.9 – FACTS is defined by IEEE as "Alternating Current Transmission Systems incorporating power electronics-based and other static controllers to enhance controllability and power transfer capability."<br><br>Item 1.10 – The assets would be identified by the asset owners. It is agreed that communication between GOs and TO/TOPs will be required.<br><br>Item 1.15 – This is the aggregate highest rated net Real Power capability output of all generation under dispatch/control.<br><br>At this time, the SDT is choosing not to add "capability," "plant," or "control center" to the NERC Glossary. We feel defining these terms under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. These terms are used in other approved NERC standards already in effect.<br><br>The requirement refers to shared cyber assets that can have a reliability impact on the group of generating units. This qualifier only includes Critical Assets identified in criterion 1.1. | | | | |
| Joseph G. DePoorter | Madison Gas and Electric Co. | 4 | Negative | The below are outstanding issues that the SDT should address before the next ballot. Comments are in line with the Unofficial Comment Form for Project 2008-06.<br>Q1: No, If a brightline is used, it removes all engineering analysis the entity is currently performing with the current CIP-002-3 methodology. This may bring in or remove assets for this Standard. A brightline approach may be useful to a smaller entity but may not be in the best interest to larger entities. The SDT should consider a brightline with a MW threshold for physical unit size or MW loads for control centers, see comments below.<br>Q2: Yes,<br>Criteria number 1.5; Based on the Rationale Document, please clarify that Facilities within the Cranking Paths will be assigned the Critical Asset identification up to the point where multiple path options exist.<br>Criteria number 1.13; Based on the Rationale Document, please clarify that the 300 MW level applies to a single common control system and not multiple like systems such as those installed for UFLS protection (multiple identical or similar individual, but independent, relays that may shed 300 MW's or more in aggregate, but individually shed less than 300 MW).<br>Criteria number 1.14; Based on the Rationale Document, every RC, BA, and TOP's control center, control system, backup control center and backup control system is Critical due to EOP-008. EOP-008-0 is the FERC approved |

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| | | | | Standard for US entities. The purpose of EOP-008-0 is: “Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable”. The SDT quoted EOP-008-1 in the Rational Document, which is not FERC approved. The SDT needs to consider this when writing a continental wide Standard. The phrase in the Rationale Document: “While it is clear that the primary and all backup control centers operated by RCs, BAs, and TOPs must be designated as Critical Assets”, is unjustified. Assuming a BA controls no critical assets qualified as such by other criteria, a BA that, in aggregate, controls relatively small amounts of real and/or reactive power clearly has less of an effect on reliability than a BA that controls relatively large amounts of such resources. Indeed, the fact that "size matters" is recognized by Criteria 1.1, 1.2, 1.6, 1.7, 1.13, and 1.15. Criterion 1.14 should be modified to recognize this conclusion by including relevant quantitative thresholds. Thresholds that were proposed in CIP-010 Criteria 1.13 and 1.14 would be reasonable. In any event, the thresholds for the BA control center or control system should be no more inclusive than those used to qualify the individual assets controlled by the BA. To complicate matters, presently there are 28 Local Balancing Authorities (LBA’s) that are part of the Midwest ISO BA Area (JRO00001). These entities do not perform all the BA functional obligations as stated in the Rationale Document (the MISO BA performs the majority of BAL-001 through BAL-005). Furthermore, the scopes of operation of the LBA’s span a wide range from small to large and few too many resources. This underscores the need to not assume that any BA (or LBA) that performs or supports any BA function or part of a BA function is necessarily critical to BES reliability. Please provide the analysis and justification to how these entities fit into the BA requirement as stated in 1.14. If it is the intent of the SDT to capture the generation within the balancing functions of a BA, the SDT has that covered by Criteria 1.15.<br>Q3: Disagree, While we agree with the general requirement of R1, we do not agree with certain aspects of Attachment 1 - Critical Asset Criteria, as discussed in responses to previous questions, above.<br>Q4: Agree<br>Q5: No, The implementation plan is clear on entities that either have in the past, identified they have CA’s or have not ever identified CA’s. The issue is present that what happens when an entity has only identified a control center as being a CA. But now they have identified a cranking path or Blackstart generator as being a CA. It is recommended that if non like items are identified as a CA, that the entity is given 24 months to become |

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| | | | | compliant. This will allow the entity enough time since they are now in an area that they may have not dealt with in the past.<br>Q6: No, See question 5. |

**Response**: Thank you for your comments.

Q1: The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology throughout North America.

Q2: Item 1.5 – The point where multiple paths exist in the Cranking Path is the step in the Transmission Operator's restoration plan per EOP-005-2 R1.5, "Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started," where the Transmission Operator can choose between the next Facilities on the BES to energize.

Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."

Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection." It is appropriate to refer to an industry approved and NERC BOT approved standard in a guidance document, even if it has not been accepted at FERC.

Q3: Please refer to response to Q2 above.

Q4: Thank you.

Q5: The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset.

Q6: The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset.

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| Mark Ringhausen | Old Dominion Electric Coop. | 4 | Negative | All of the following comments apply to the Attachment 1:<br>General Comments: For the cases where any other entity (PC/TP) would declare that other entity has a Critical Asset, there must be a phase-in compliance process to allow the entity with the CA to get into compliance with the CIP requiorments. Also, there must be a due process procedure to allow the entity with the designated CA to challenge this at the Region or NERC level.<br>1.3: PC/TP must have a formal process to determine whether or not a generation faciltiy is needed for reliabiltiy or not. This process must be provided to each generation owner and operator under review by the PC/TPs.<br>1.5: The Cranking Paths adn initial switching requirements must be provided by the TOP to the TO in cases where these are two different entities.<br>1.10: You need to better described which facilities you are trying to cover here. Any transmission facility which if lost would result in the loss of >1500MWs or a PC/TP designated generation facility for reliability.<br>1.13: Should match 1.1, change 300MWs to 1500MWs. Impact of losing 1500MWs of generation is still greater than losing 1500MWs of load. |

**Response**: Thank you for your comments.

The burden for identifying Critical Assets is with the Responsible Entity that is the asset owner. The Responsible Entity has to check with its Planning Coordinator or Transmission Planner on whether its unit is designated, or what other units are designated as required for reliability reasons. If it is determined through system studies that a unit must run in order to preserve the reliability of the BES, then that unit must be classified as a Critical Asset. If an entity feels that they have an asset that has been unjustly classified as required for reliability reasons, there are appeals processes that can be used.

Item 1.3 – This criterion has been reworded to “Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.”

Item 1.5 – Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in EOP-005-2 to “provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan.”

Item 1.10 – The intent is to ensure the availability of Facilities necessary to support those generation Critical Assets. Any transmission Facility that, if lost, would result in the loss of a Critical Asset identified in criterion 1.1 or 1.3 would need to be classified as a Critical Asset. That might include the partial or total loss of a substation. This criterion has been changed to “Transmission Facilities providing the generation interconnection required to connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets identified by any Generator Owner as a result of its application of Attachment 1, criterion 1.1

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| or 1.3.”<br><br>Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.” | | | | |
| John D. Martinsen | Public Utility District No. 1 of Snohomish County | 4 | Negative | The way CIP-002-4 attachment 1 - 1.13 is worded is a concern- would any RE with a load over 970 MW in the Western Interconnection have critical assets just because their UFLS scheme has armed 31% of their load- meeting the 300 MW threshold? There are already PRC standards to address these systems, so we don’t believe that the 300 MW “bright line” threshold is reasonable. |
| **Response**: Thank you for your comments.<br><br>Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.” | | | | |
| Mike Ramirez | Sacramento Municipal Utility District | 4 | Negative | After reviewing the proposed version 4 language for CIP-002, R2, the placement of the additional text on generation is confusing. It appears to be trying to accomplish two different purposes. SMUD does not have any objections to the text itself, just the placement. SMUD proposes organizing the requirement as follows: R2. Critical Cyber Asset Identification- Using the list of Critical Assets developed pursuant to Requirement R1, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. The Responsible Entity shall review this list at least annually, and update it as necessary. R2.1 For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics: R2.1.1 The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or, R2.1.2 The Cyber Asset uses a routable protocol within a control center; or, R2.1.3 The Cyber Asset is dial-up accessible. R2.2 For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1., the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes. Additionally, SMUD, as a member of APPA, would like to reflect its support to those CIP-002-4 Standard comments submitted by APPA staff. |

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| **Response**: Thank you for your comments. Please refer to the response to comments document for responses to APPA comments.<br><br>Requirement R2 has been changed to clarify the issues presented. | | | | |
| Anthony Jankowski | Wisconsin Energy Corp. | 4 | Negative | Your responses to the following questions will assist the SDT for Project 2008-06 Cyber Security Order 706 in finalizing the work for CIP-002-4 through CIP-009-4 relative to the proposed modifications summarized above. For each question, please indicate whether or not you agree with the modification being proposed. If you disagree with the proposed modification, please explain why you disagree and provide as much detail as possible regarding your disagreement including any suggestions for altering the proposed modification that would eliminate or minimize your disagreement. The SDT would appreciate responses to as many of these questions as you are willing to supply.<br>1. When reviewing the mapping document posted with the proposed CIP-002-4 standard, do you believe that the proposed standard will lead to an improvement in reliability when compared to the standard it proposes to replace? 1 Yes 0 No Comments: We understand that the errata, which removes discussion of the “risk-based assessment methodology” from the proposed CIP-002-4 standard, would also apply to the mapping document. We appreciate the bright-line clarification to ensure consistent identification of Critical Assets throughout the industry.<br>2. CIP-002-4 Attachment 1 contains criteria that define elements that must be classified as Critical Assets. Do you have any suggestions that would improve the proposed criteria? If so, please explain and provide specific suggestions for improvement. 1 Yes 0 No Comments:<br>We suggest that the functional entities Planning Coordinator and Transmission planner be added to the applicability section. Feedback on specific criteria as follows:<br>1.1, We request clarification on the phrase “single plant location”. This phrase is not defined and it is not clear what level of proximity of generators would be considered a “single plant location”. Rather than discuss this in terms of geography (location), we feel it would be better to discuss in terms of “Each group of generating units (including nuclear generation), operated using common cyber control systems other than the Control Centers identified in 1.14 and 1.15, with an aggregate…”.<br>1.3, We suggest the wording: “Each generation facility designated by the Planning Coordinator or Transmission Planner as required to avoid one or more reliability criteria violations”.<br>1.4, The blackstart units deemed critical should be only those identified by |

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| | | | | the Transmission Operator to meet the minimum critical blackstart requirement. The resulting suggested wording would be: “Each Blackstart Resource identified in the Transmission Operator’s restoration plan required to meet the minimum critical blackstart requirement”.<br>1.8, We suggest the wording: “Transmission Facilities at a single location that the Planning Coordinator or Transmission planner has designated that, if destroyed, degraded, misused or otherwise rendered unavailable, would result in one or more Interconnection Reliability Operating Limit (IROL) violations”.<br>1.9, We suggest similar wording: “...unavailable, would result in one or more Interconnection Reliability Operating Limit (IROL) violations”.<br>1.11, We suggest the following wording: “Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements”.<br>1.12, We suggest the following wording: “...unavailable, would cause one or more Interconnection Reliability Operating Limit (IROL) violations for failure to operate as designed”.<br>1.14, We suggest this be made consistent with 1.15, i.e. “Each control center, or backup control center, used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator”.<br>1.16, We suggest the following wording: “Any additional assets owned by the Responsible Entity that the Responsible Entity deems appropriate to include”.<br>3. Requirement R1 of draft CIP-002-4 states, “Critical Asset Identification - Each Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the criteria contained in CIP-002-4 Attachment 1 - Critical Asset Criteria. The Responsible Entity shall review this list at least annually, and update it as necessary.” Do you agree with the proposed Requirement R1? If not, please explain why and provide specific suggestions for improvement. 1 Agree 0 Disagree Comments:<br>4. Requirement R2 of draft CIP-002-4 states, “Using the list of Critical Assets developed pursuant to Requirement R1, each Responsible Entity shall develop a list of associated Critical Cyber Assets performing a function essential to the operation of the Critical Asset. For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed |

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| | | | | Attachment 1, criterion 1.1 within 15 minutes. Each Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics". The requirement then lists characteristics using the same text that is contained in the existing CIP-002-3 R3. Do you agree with the proposed Requirement R2? If not, please explain why and provide specific suggestions for improvement. 1 Agree 0 Disagree Comments: Although we agree with the proposed Requirement R2, We are concerned that the document "CIP-002-4 Cyber Security - Critical Cyber Asset Identification: Rationale and Implementation Reference Document" actually appears to provide more rationale and guidance on Critical Assets than Critical Cyber Assets.<br>5. Do you agree with the proposed implementation plan for the Version 4 standards? If not, please explain and provide specific suggestions for improvement. 1 Yes 0 No Comments:<br>6. Do you agree with the proposed revisions to the implementation plan for newly identified CCAs and Responsible Entities? If not, please explain and provide specific suggestions for improvement. 0 Yes 1 No Comments: We believe that it would be better to simply have a uniform 18 month implementation deadline for newly identified CCAs rather than have different timelines for different requirements. This will simplify reporting and streamline efforts to become fully compliant. We understand that nuclear timelines are subject to NRC requirements and the necessity of accomplishing some tasks only during refueling outages appropriately dictates a separate schedule for them. |

**Response**: Thank you for your comments.

Q2. Since there is no Requirement that applies to the Planning Coordinator or the Transmission Planner, it is not appropriate to include them in the Applicability section.

Item 1.1 – The guidance document posted by the SDT provides direction on the location issue. "Single plant location" refers to a group of generating units occupying a defined physical footprint and designated as an individual "plant" using commonly accepted generating facility terminology. Adjacent plants would be defined using the same criteria. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant.

Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."

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| Item 1.4 – A Blackstart Resource is defined as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.” The SDT feels that these units must be classified as Critical Assets. It should be noted that not all blackstart generators are Blackstart Resources.<br><br>Item 1.8 – According to FAC-014-2, IROLs are established by Transmission Operators, Transmission Planners, and Planning Authorities. The Reliability Coordinator ensures that IROLs are established and are consistent with its methodology. The present wording is appropriate. This criterion has been changed to “Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.”<br><br>Item 1.9 – This criterion has been changed to “Flexible AC Transmission Systems (FACTS), at a single station or substation location, that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.”<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2 “Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.” It is not limited to offsite power requirements.<br><br>Item 1.12 – This criterion has been changed to “Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limit (IROL) violations for failure to operate as designed.”<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot.<br><br>Q4. Thank you for your comments. The SDT will reexamine the guidance document.<br><br>Q5. Due to the limited scope of version 4, the SDT is only making conforming changes to the Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities. | | | | |

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Brock Ondayko</td><td>AEP Service Corp.</td><td>5</td><td>Negative</td><td>Overall, AEP is supportive of the efforts and the general concepts of this draft; however, there are a few refinements that will enhance the requirements and remove ambiguity. AEP encourages the SDT to consider the items below in a future draft of the standard:<br>AEP would contend that there are regional differences that would be relevant to determine a MW threshold for generators. We support the concept that was contained in the last draft that made the determination based on the capacity reserves. However, the prior language would need to be revisited to ensure that value was fixed for a period of time.<br>In addition, requirement 2.2 uses the term control center (also used in attachment 1) that is not a NERC defined term. This will introduce ambiguity to implementation. There has been ongoing confusion regarding the difference between “control centers” and “control rooms.” We do not believe that a “control room” at a power plant or a substation would be considered a “control center.” There is language in the NERC Security Guideline for Electricity Sector: Identifying Critical Assets document that the SDT should consider and incorporate into the NERC Glossary.<br>Net real power capability testing is defined in MOD-024 standards that have yet to be FERC approved. Furthermore, not all of the regions have defined the parameters for the capability testing.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>Item 1.1 - In prior versions we had wording about reserve sharing for the threshold.  We received feedback that that wording was confusing, that the amount referred to in the reserve sharing was not a specific amount, and that the amounts changed daily.  We did an informal survey of the regions, and we identified what the megawatt value of the reserve sharing would be for various groups.  The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BAs in all regions.<br><br>At this time, the SDT is choosing not to add control center to the NERC Glossary.  We feel defining this term under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4.  This term is used in other approved NERC standards already in effect.<br><br>CIP-002-4 does not require net real power capability testing.</td></tr>
<tr><td>Brad Haralson</td><td>Associated Electric Cooperative, Inc.</td><td>5</td><td>Negative</td><td>please see submitted comments</td></tr>
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| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Clement Ma | BC Hydro and Power Authority | 5 | Negative | Critical Assets List comments<br>1.7. Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations The present wording uses an arbitrary numbers of stations, the number of stations is immaterial BCH recommends the “Transmission Facilities operated at 300 kV or higher that if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs).<br>1.13. Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes. A clear definition of common control system(s) is required. Is under frequency or under voltage load shedding schemes considered control systems? The load shedding of 300 MW or more does it include firm or interruptible load or both?<br>1.16. Any additional assets that the Responsible Entity deems appropriate to include. To encourage reliability the additional assets deemed appropriate by a Responsible Entity should not be auditable. |
| **Response**: Thank you for your comments.<br><br>Item 1.7 – In order to be more accurate in terms of the impact, the drafting team thought that it was more appropriate to refer to the number of connected transmission substations instead of using IROLs. The intent was to avoid double-circuit conditions and to include facilities that are actually more a part of the network than simple substations with double circuits between them. This includes upstream, downstream, radial and networked substations.<br><br>Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot. | | | | |
| Francis J. Halpin | Bonneville Power Administration | 5 | Negative | Please refer to BPA comments submitted during the formal comment period on 10/26/10 |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |

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| Jeff Mead | City of Grand Island | 5 | Negative | I echo the MRO NSRS comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Alan Gale | City of Tallahassee | 5 | Negative | The City of Tallahassee supports APPA's comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| James B Lewis | Consumers Energy | 5 | Negative | In Criteria 1.4, we would prefer to see Blackstart Resources for primary paths only specified. The way it is written, all Blackstart Resources, inlcuding those for alternate paths, would be included. This creates ambiguity as there are very many possible alternate cranking paths. We dislike Criteria 1.5 and the wording in the Rationale Document. Similar to 1.4, the words "primary path" are no longer used and depending on interpretation, additional resources on what are now alternate cranking paths could be brought into play. The Standard should be clear and not subject to interpretation. |
| **Response**: Thank you for your comments.<br><br>Items 1.4 and 1.5 – The SDT considered using the word “primary”, but ultimately rejected it as it is not a defined NERC Glossary term in this instance, nor is it used in EOP-005-2. A Blackstart Resource is defined as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.” EOP-005-2 R1.4 states that the restoration plan must include “Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.” The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources. | | | | |
| Bob Essex | Cowlitz County PUD | 5 | Negative | The Attachment is too inclusive. Please refer to Cowlitz County PUD and APPA comments. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |

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| Robert B Stevens | CPS Energy | 5 | Negative | I believe the standard is going the correct direction. However, I would modify one definition on the Attachment. The Attachment reads "generating units (including nuclear generation) at a single plant location" I would propose the same language but add "connected to transmission grid at one location or one buss", or something similar. The problem arises where you have multiple generating units at one plant location, but a set of plants feed into 345 switchgear and a set of plants feeds into 138 switchgear. You have two distinct reliability situations, thus the need to distinguish. |
| **Response**: Thank you for your comments.<br><br>Item 1.1 – The guidance document posted by the SDT provides direction on the location issue. "Single plant location" refers to a group of generating units occupying a defined physical footprint and designated as an individual "plant" using commonly accepted generating facility terminology. Adjacent plants would be defined using the same criteria. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant. | | | | |
| Mike Garton | Dominion Resources, Inc. | 5 | Negative | Dominion conceptually supports bright line criteria for determining critical assets. However, we cannot vote in favor at this time because we believe that changes are needed in Table 2 that recognize the implementation for infrastructure (physical and electronic security) should be equal to, or longer than, that required for training. We also believe that the bright line criteria for generation control center needs further effort. Please see more specific comments/recommendation submitted by Dominion. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Stephen Ricker | East Kentucky Power Coop. | 5 | Negative | EKPC would suggest rewording R2 to say: "For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those interconnected Cyber Assets that collectively could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes." |
| **Response**: Thank you for your comments. Requirement R2 has been changed based on industry comments received. | | | | |
| Stanley M Jaskot | Entergy Corporation | 5 | Negative | Switchyards serving nuclear facilities should not be automatically classified as critical assets. The fact that a BES switchyard serves a nuclear facility should not in itself qualify the switchyard as a critical asset. While nuclear units and their support facilities may qualify as critical assets under a |

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| | | | | separate set of criteria, they should not automatically be designated as critical to the BES without some measure of the impact of the loss of the facility on BES reliability.<br>All blackstart units and associated cranking paths should not be automatically classified as critical assets. Blackstart units may be useful in the restoration of the BES following a large scale outage, but they are not necessarily essential to the reliability of the BES under normal operation. Blackstart units should not automatically be designated as critical to the BES without some measure of the impact of the loss of the facility on BES reliability.<br>In addition, just using a MW or MVAR rating alone in determining critical assets is not enough. It needs to be coupled with a service factor because we have a large generating station thay runs very infrequently and should not be deemed critical based on its operation. In addition, Entergy presented many other comments and suggested changes during the development of this draft standard. Entergy continues to support those comments even though some were not incorporated into this standard. |
| **Response**: Thank you for your comments.<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2 "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." Since these facilities were deemed so important that a NERC standard was written and adopted to clarify the issue, the SDT determined that this was adequate justification to include them as Critical Assets.<br><br>Item 1.4 – A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." The SDT feels that these units must be classified as Critical Assets. It should be noted that not all blackstart generators are Blackstart Resources.<br><br>Item 1.1 – The SDT debated whether to include capacity factor in this criterion. The reason we ultimately chose not to include capacity factor is twofold. First, there is no consistent method to select an appropriate capacity factor, and low capacity factor units may be critical to the system at peak load conditions. Second, there was concern that some units might fall below the line during major outage periods, taking them off the Critical Asset list one year and putting them back on the list the next year. | | | | |
| David Schumann | Florida Municipal Power Agency | 5 | Negative | FMPA commends the SDT on making significant headway on the version 4 standards. However, there are significant additional improvement that should be made to make the criteria of Attachment 1 less arbitrary and that truly measures those assets that can have an Adverse Reliability Impact. Also, the standard is still unclear in several areas, such as how to identify CCAs at a substation if a substation is determined to be a CA that |

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| | | | | needs to be clarified. Please see FMPA's comments submitted through the formal comment process for more specific detail and proposed alternatives. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Brent Hebert | Horizon Wind Energy | 5 | Negative | Part 1.15 designates generation control centers that control generation Facilities used to control generation greater than an aggregate of 1500 MW in a single interconnection and was based on the bright-line used in Part 1.1. Part 1.1 includes generation at a single plant location (with-in a single BA or RSG). Part 1.15 should be more in line with part 1.1 where the generation control center controlling generation with an aggregate of 1500 MW or more within a single BA or RSG be designated as critical. It is true that the span of control of a generation control center may cross multiple BAs or RSG, but the control of generation within a single BA or RSG could fall well below the 1500 MWs in Part 1.1. even if located in a single interconnection. |
| **Response**: Thank you for your comments.<br><br>Item 1.15 –This criterion has been changed to "Each control center or backup control center used to control generation at multiple plant locations, for any generation Facility or group of generation Facilities identified in criteria 1.1, 1.3, or 1.4. Each control center or backup control center used to control aggregate generation equal to or exceeding 1500 MWs in a single Interconnection." | | | | |
| Dennis Florom | Lincoln Electric System | 5 | Negative | Please review the comments submitted by the MRO's NERC Standards Review Subcommittee for LES' reasons for a negative ballot. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Mike Laney | Luminant Generation Company LLC | 5 | Negative | Luminant Generation Company LLC (Luminant Generation) thanks the Standard Drafting Team (SDT) for their work on the NERC CIP Cyber Security Standards and for the opportunity to provide input into the standards development process. Although Luminant Generation has voted "Negative" on the current draft standard, Luminant Generation supports the SDT goal of completing the revision of CIP-002-4 by December 2010, and believes with some modification to the Attachment 1 Criteria, the goal is still achievable.<br>Specifically, Luminant Generation is concerned that Criteria 1.3 has no defined basis for determining the reliability need of a generation Facility. As written, the Planning Coordinator or Transmission Planner could use any |

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| | | | | basis, or conversely, no basis, for designating a generation Facility as required for reliability purposes. For Criteria 1.8, 1.9, and 1.12, the SDT has appropriately used the violation of an Interconnection Reliability Operating Limit (IROL) as the basis for determining the reliability need of transmission Facilities. Luminant Generation believes this same basis is appropriate for application to generation Facilities in Criteria 1.3, and offers the following language for consideration by the SDT: 1.3 "Each generation Facility that the Planning Coordinator or Transmission Planner designates as required for reliability purposes, by demonstrating that the generation facility, if destroyed, degraded, misused or otherwise rendered unavailable, would violate one or more Interconnection Reliability Operating Limits (IROLs)." |
| **Response**: Thank you for your comments.<br><br>Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon." | | | | |
| Steven Schultz | Madison Gas and Electric Co. | 5 | Negative | The below are outstanding issues that the SDT should address before the next ballot. Comments are in line with the Unofficial Comment Form for Project 2008-06.<br>Q1: No, If a brightline is used, it removes all engineering analysis the entity is currently performing with the current CIP-002-3 methodology. This may bring in or remove assets for this Standard. A brightline approach may be useful to a smaller entity but may not be in the best interest to larger entities. The SDT should consider a brightline with a MW threshold for physical unit size or MW loads for control centers, see comments below.<br>Q2: Yes,<br>Criteria number 1.5; Based on the Rationale Document, please clarify that Facilities within the Cranking Paths will be assigned the Critical Asset identification up to the point where multiple path options exist.<br>Criteria number 1.13; Based on the Rationale Document, please clarify that the 300 MW level applies to a single common control system and not multiple like systems such as those installed for UFLS protection (multiple identical or similar individual, but independent, relays that may shed 300 MW's or more in aggregate, but individually shed less than 300 MW).<br>Criteria number 1.14; Based on the Rationale Document, every RC, BA, and TOP's control center, control system, backup control center and backup control system is Critical due to EOP-008. EOP-008-0 is the FERC approved Standard for US entities. The purpose of EOP-008-0 is: "Each reliability entity must have a plan to continue reliability operations in the event its |

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| | | | | control center becomes inoperable". The SDT quoted EOP-008-1 in the Rational Document, which is not FERC approved. The SDT needs to consider this when writing a continental wide Standard. The phrase in the Rationale Document: "While it is clear that the primary and all backup control centers operated by RCs, BAs, and TOPs must be designated as Critical Assets", is unjustified. Assuming a BA controls no critical assets qualified as such by other criteria, a BA that, in aggregate, controls relatively small amounts of real and/or reactive power clearly has less of an effect on reliability than a BA that controls relatively large amounts of such resources. Indeed, the fact that "size matters" is recognized by Criteria 1.1, 1.2, 1.6, 1.7, 1.13, and 1.15. Criterion 1.14 should be modified to recognize this conclusion by including relevant quantitative thresholds. Thresholds that were proposed in CIP-010 Criteria 1.13 and 1.14 would be reasonable. In any event, the thresholds for the BA control center or control system should be no more inclusive than those used to qualify the individual assets controlled by the BA. To complicate matters, presently there are 28 Local Balancing Authorities (LBA's) that are part of the Midwest ISO BA Area (JRO00001). These entities do not perform all the BA functional obligations as stated in the Rationale Document (the MISO BA performs the majority of BAL-001 through BAL-005). Furthermore, the scopes of operation of the LBA's span a wide range from small to large and few too many resources. This underscores the need to not assume that any BA (or LBA) that performs or supports any BA function or part of a BA function is necessarily critical to BES reliability. Please provide the analysis and justification to how these entities fit into the BA requirement as stated in 1.14. If it is the intent of the SDT to capture the generation within the balancing functions of a BA, the SDT has that covered by Criteria 1.15.<br>Q3: Disagree, While we agree with the general requirement of R1, we do not agree with certain aspects of Attachment 1 - Critical Asset Criteria, as discussed in responses to previous questions, above.<br>Q4: Agree<br>Q5: No, The implementation plan is clear on entities that either have in the past, identified they have CA's or have not ever identified CA's. The issue is present that what happens when an entity has only identified a control center as being a CA. But now they have identified a cranking path or Blackstart generator as being a CA. It is recommended that if non like items are identified as a CA, that the entity is given 24 months to become compliant. This will allow the entity enough time since they are now in an area that they may have not dealt with in the past. |

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<tr><td></td><td></td><td></td><td></td><td>Q6: No, See question 5.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>Q1: The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology throughout North America.<br><br>Q2: Item 1.5 – The point where multiple paths exist in the Cranking Path is the step in the Transmission Operator’s restoration plan per EOP-005-2 R1.5, “Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started,” where the Transmission Operator can choose between the next Facilities on the BES to energize.<br><br>Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.” It is appropriate to refer to an industry approved and NERC BOT approved standard in a guidance document, even if it has not been accepted at FERC.<br><br>Q3: Please refer to response to Q2 above.<br><br>Q4: Thank you.<br><br>Q5: The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset.<br><br>Q6: The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset.</td></tr>
<tr><td>Steven Grego</td><td>MEAG Power</td><td>5</td><td>Negative</td><td>MEAG supports the APPA’s comments submitted to the NERC CIP standard drafting team.</td></tr>
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| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Don Schmit | Nebraska Public Power District | 5 | Negative | NPPD comments are addressed by comments submitted through APPA. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Patricia A. Lynch | NRG Energy, Inc. | 5 | Negative | Pertaining to CIP-002-4 R1, the following need to be addressed in Attachment 1:<br>1.1 - Add capacity factor as a qualifier for exclusion below an established low threshold.<br>1.3 - Mandate coordination/approval process between the Transmission Planner and entity that have been designated critical by the Transmission Planner. These classifications and approvals need to take into consideration 5 year forecasts for planning and budgeting purposes..<br>1.5 - TOP needs to define the cranking path in restoration plan to the affected entities to adequately secure these restoration paths..<br>1.9 - Please explain FACTS - need definition<br>1.10 - Need coordination between TOP & GO to identify critical assets.<br>1.15 - How is the 1500 MW aggregate determined? Is it an aggregate of generator name plates or the sum of controllable megawatts between a unit's high and low limits?<br>General: Attachment 1 needs to have defined terms for capability, plant, control center Requirement 2 needs to clarify the following items:<br>1) Need Clarification on routable path, discrete links and serial connections as it pertains to CIP-002-3 R3: Is a device considered to communicate outside the ESP using routable protocol if ANY portion of the communications path uses routable protocol?<br>2)Need clarification concerning shared assets. Does it mean shared between a single device or same device on a network?<br>3)R2 states that only shared cyber assets for a group of generating units at a single location identified in Attachment 1 criteria 1.1, namely the 1500 MWs brightline, that could impact reliable operation, should be considered. Does this cyber asset identification only include assets meeting criteria 1.1 and therefore exclude any cyber assets utilized for reliable operation of a designated critical asset such as a single blackstart resource? Please |

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| | | | | provide clarification in this requirement. |
| **Response**: Thank you for your comments.<br><br>Item 1.1 – The SDT debated whether to include capacity factor in this criterion. The reason we ultimately chose not to include capacity factor is twofold. First, there is no consistent method to select an appropriate capacity factor, and low capacity factor units may be critical to the system at peak load conditions. Second, there was concern that some units might fall below the line during major outage periods, taking them off the Critical Asset list one year and putting them back on the list the next year.<br><br>Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."<br><br>Item 1.5 – Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."<br><br>Item 1.9 – FACTS is defined by IEEE as "Alternating Current Transmission Systems incorporating power electronics-based and other static controllers to enhance controllability and power transfer capability."<br><br>Item 1.10 – The assets would be identified by the asset owners. It is agreed that communication between GOs and TO/TOPs will be required.<br>Item 1.15 – This is the aggregate highest rated net Real Power capability output of all generation under dispatch/control.<br><br>At this time, the SDT is choosing not to add "capability," "plant," or "control center" to the NERC Glossary. We feel defining these terms under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. These terms are used in other approved NERC standards already in effect.<br><br>The requirement refers to shared cyber assets that can have a reliability impact on the group of generating units. This qualifier only includes Critical Assets identified in criterion 1.1. | | | | |
| Colin Anderson | Ontario Power Generation Inc. | 5 | Negative | Section 4.2.1 in previous versions of CIP-002 used to exempt "Facilities regulated by the US Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission". This exemption has been removed in draft CIP-002 version 4. Canada has its own laws and regulations and all nuclear facilities within Canada are covered by them. The CNSC regulates the complete nuclear site and we are of the strong opinion that a single regulator (CNSC) should have jurisdiction over the full operating island of nuclear assets due to the over-riding concern for nuclear safety issues. The cyber security standards should be under the jurisdiction of the CNSC in Canada. As such, Section 4.2.1 in CIP-002-4 should continue to exempt the |

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| | | | | following; "Facilities regulated by the Canadian Nuclear Safety Commission". |
| **Response**: Thank you for your comments.<br><br>The SDT is aware that the removal of the nuclear plant exclusion in response to a FERC order brought Canadian nuclear plants into the CIP standards. That was unintentional and will be corrected in the revised standards next posted for ballot. | | | | |
| Richard Kinas | Orlando Utilities Commission | 5 | Negative | comments submitted through online comment form |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Richard J. Padilla | Pacific Gas and Electric Company | 5 | Negative | While we understand the need to have a consistent application across the BES, the brightline methodology does not provide enough flexibility to determine what is a critical asset. We recommend an additional attempt to develop guiding principles for determining critical facilities without unilateral declarations on what is critical. The standard development process is still too much in the infant stage with vague definitions. Flexibility is needed to allow entities to develop their CIP responses to meet their critical needs. |
| **Response**: Thank you for your comments.<br><br>The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. | | | | |
| Tim Hattaway | PowerSouth Energy Cooperative | 5 | Negative | Primary concern that a blanket statement of "all blackstart resources" would effectively incentivize utilities to write out blackstart resources to avoid the protection involved, ultimately decreasing the reliability of the system. Perhaps a better requirement would be blackstart resources identified as primary restoration components in a region's restoration plans. |
| **Response**: Thank you for your comments.<br><br>Item 1.4 – A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." The SDT feels that these units must be classified as Critical Assets. It should be noted that not all blackstart generators are Blackstart Resources. | | | | |

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| Jerzy A Slusarz | PSEG Power LLC | 5 | Negative | Project 2008-06: Cyber Security - Order 706 November, 2010 |
| **Response**: Thank you for your comments. | | | | |
| Thomas J. Bradish | RRI Energy | 5 | Negative | Criteria 1.6 and 1.7 are arbitrary without clarification and in relation to Criteria 1.10. Suggest adding the following clarification to the end of Criteria 1.6 and 1.7: ", unless the Transmission Facilities only provide the generation interconnection required to directly connect generator output to the transmission system."<br>o Criteria 1.6, as modified, should read as follows: "Transmission Facilities operated at 500-kV or higher, unless the Transmission Facilities only provide the generation interconnection required to directly connect generator output to the transmission system."<br>o Criteria 1.7, as modified, should read as follows: "Transmission Facilities operated at 300-kV or higher at stations interconnected at 300-kV or higher with three or more other transmission stations, unless the Transmission Facilities only provide the generation interconnection required to directly connect generator output to the transmission system."<br>Clarifications such as the ones presented above and with respect to Criteria 1.6 and Criteria 1.7 would be unnecessary if the Drafting Team first acknowledged the technical distinction between "generator interconnection facilities" and "transmission facilities." Without such a distinction, radial generator interconnection facilities are indistinguishable from parallel transmission facilities and, as a result, there are mis-applications of the registration criteria and mis-applications of Reliability Standards such as in the case of the Milford and Cedar Creek wind farms. The Drafting Team should take special aim at avoiding further codification of such technically deficient mis-applications in the CIP Reliability Standards. |
| **Response**: Thank you for your comments.<br><br>Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Asset a Transmission Facility operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations. | | | | |

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| Bethany Wright | Sacramento Municipal Utility District | 5 | Negative | After reviewing the proposed version 4 language for CIP-002, R2, the placement of the additional text on generation is confusing. It appears to be trying to accomplish two different purposes. SMUD does not have any objections to the text itself, just the placement. SMUD proposes organizing the requirement as follows: R2. Critical Cyber Asset Identification- Using the list of Critical Assets developed pursuant to Requirement R1, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. The Responsible Entity shall review this list at least annually, and update it as necessary. R2.1 For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics: R2.1.1 The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or, R2.1.2 The Cyber Asset uses a routable protocol within a control center; or, R2.1.3 The Cyber Asset is dial-up accessible. R2.2 For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1., the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes. Additionally, SMUD, as a member of APPA, would like to reflect its support to those CIP-002-4 Standard comments submitted by APPA staff. |
| **Response**: Thank you for your comments. Please refer to the response to comments document for responses to APPA comments.<br><br>Requirement R2 has been changed to clarify the issues presented. | | | | |
| Glen Reeves | Salt River Project | 5 | Negative | SRP believes that a bright line assessment methodology for determining Critical Assets is not in the best interest of reliability. This is especially true in the designation of substations and generating facilities. The attributes of these stations and their unique impact on Bulk Electric System reliability must be taken into account. There are several terms and phrases used within Requirement 2 of the proposed Standard that need to be better defined to eliminate ambiguity. These terms are: 1) essential to the operation of the Critical Asset, 2) adversely impact the reliable operation needs to be defined; and, 3) within 15 minutes. We believe the CIP-002-4 implementation plan for newly identified Critical Assets and associated Critical Cyber Assets provides inadequate time. SRP suggests the implementation timeframe be extended to 30 months after the effective date of the Standard. |

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| **Response**: Thank you for your comments.<br><br>The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues.<br><br>The phraseology you are concerned about (annual) exists in the existing CIP-002-3 standard. The SDT expects this phraseology to be resolved in the next version.<br><br>Thank you for your comment. The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset. | | | | |
| George T. Ballew | Tennessee Valley Authority | 5 | Negative | Tennessee Valley Authority (TVA) appreciates the opportunity to comment on this CIP-002-4 draft. We fully support the standards development process and all the hard work and commitment by the drafting team members. For this draft, we have the following concerns which moved us to cast a Negative vote. Q1: Yes; no comment<br>Q2: 1.4. Each Blackstart Resource identified in the Transmission Operator's restoration plan. The language appears to require us to designate “Each” component in the System Restoration plan as CA. Because we currently include at least 2 paths for black start of most generation plants in the system, the proposed language would require the extension of CA designation to a large number of components which otherwise would not be included by other criteria. The flexibility provided by our robust transmission infrastructure and the large number of black start capable plants serves to ensure reliable operation of the BES, but designating as a CA each component that could participate in the total paths possible doesn’t seem consistent with the intent of the standard. Recommendation: Revise language to allow entities to limit CA designation to those components participating in the primary black start path.<br>1.10. Transmission Facilities providing the generation interconnection required to directly connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3. There isn’t a clear definition of the term “directly connected.” Without this definition there are many way to interpret this requirement. Is this language meant to describe a facility where the substation is co-located with a generation facility? Also, does the language this mean total loss of substation or only partial? Recommendation: For the purpose of this |

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| | | | | standard revise language to clearly define "directly connected."<br>Q3: Yes; no comment<br>Q4: Yes; no comment<br>Q5: abstain<br>Q6: abstain |
| **Response**: Thank you for your comments.<br><br>Item 1.4 – The SDT considered using the word "primary", but ultimately rejected it as it is not a defined NERC Glossary term, nor is it used in EOP-005-2. A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." EOP-005-2 R1.4 states that the restoration plan must include "Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit." The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources.<br><br>Item 1.10 – The intent is to ensure the availability of Facilities necessary to support those generation Critical Assets. Any transmission Facility that, if lost, would result in the loss of a Critical Asset identified in criterion 1.1 or 1.3 would need to be classified as a Critical Asset. That might include the partial or total loss of a substation. | | | | |
| Karl Bryan | U.S. Army Corps of Engineers Northwestern Division | 5 | Negative | The Standards Drafting Team has chosen to be prescriptive in determining Critical Assets. The Responsible Entity is responsible for identifying Critical Assets and FERC directed NERC to provide additional guidance in helping the Responsible Entity determine Critical Assets and for NERC to maintain flexibility for the Responsible Entity in the determination of Critical Assets. The prescriptive nature of the approach being used in the Ver 4 CIP Standard appears to be taking the responsibility of determining Critical Assets away from the Responsible Entity and the lack of flexibility may eliminate or preclude a system or component from being identified as a Critical Asset. |
| **Response**: Thank you for your comments. Regarding the directives for external review and guidance in the FERC Order, the SDT believes the criteria in Attachment 1 are in response to FERC Order 706 paragraph 329. In consideration of this directive, the SDT decided there did not exist across all regions an appropriate third party to provide this type of oversight. Also, external review and oversight carries with it the compliance overhead and arbitration processes analogous to the TFE process. This "bright-line" approach removes the variability of entity defined methodologies that would prompt the need for external review. | | | | |
| Linda Horn | Wisconsin Electric Power Co. | 5 | Negative | 1. When reviewing the mapping document posted with the proposed CIP-002-4 standard, do you believe that the proposed standard will lead to an improvement in reliability when compared to the standard it proposes to replace? 1 Yes 0 No Comments: We understand that the errata, which removes discussion of the "risk-based assessment methodology" from the |

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| | | | | proposed CIP-002-4 standard, would also apply to the mapping document. We appreciate the bright-line clarification to ensure consistent identification of Critical Assets throughout the industry.<br>2. CIP-002-4 Attachment 1 contains criteria that define elements that must be classified as Critical Assets. Do you have any suggestions that would improve the proposed criteria? If so, please explain and provide specific suggestions for improvement. 1 Yes 0 No Comments: We suggest that the functional entities Planning Coordinator and Transmission planner be added to the applicability section. Feedback on specific criteria as follows:<br>1.1, We request clarification on the phrase “single plant location”. This phrase is not defined and it is not clear what level of proximity of generators would be considered a “single plant location”. Rather than discuss this in terms of geography (location), we feel it would be better to discuss in terms of “Each group of generating units (including nuclear generation), operated using common cyber control systems other than the Control Centers identified in 1.14 and 1.15, with an aggregate...”.<br>1.3, We suggest the wording: “Each generation facility designated by the Planning Coordinator or Transmission Planner as required to avoid one or more reliability criteria violations”.<br>1.4, The blackstart units deemed critical should be only those identified by the Transmission Operator to meet the minimum critical blackstart requirement. The resulting suggested wording would be: “Each Blackstart Resource identified in the Transmission Operator’s restoration plan required to meet the minimum critical blackstart requirement”.<br>1.8, We suggest the wording: “Transmission Facilities at a single location that the Planning Coordinator or Transmission planner has designated that, if destroyed, degraded, misused or otherwise rendered unavailable, would result in one or more Interconnection Reliability Operating Limit (IROL) violations”.<br>1.9, We suggest similar wording: “...unavailable, would result in one or more Interconnection Reliability Operating Limit (IROL) violations”.<br>1.11, We suggest the following wording: “Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements”.<br>1.12, We suggest the following wording: “...unavailable, would cause one or more Interconnection Reliability Operating Limit (IROL) violations for failure to operate as designed”.<br>1.14, We suggest this be made consistent with 1.15, i.e. “Each control center, or backup control center, used to perform the functional obligations |

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| | | | | of the Reliability Coordinator, Balancing Authority, or Transmission Operator”.<br>1.16, We suggest the following wording: “Any additional assets owned by the Responsible Entity that the Responsible Entity deems appropriate to include”.<br>3. Requirement R1 of draft CIP-002-4 states, “Critical Asset Identification - Each Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the criteria contained in CIP-002-4 Attachment 1 - Critical Asset Criteria. The Responsible Entity shall review this list at least annually, and update it as necessary.” Do you agree with the proposed Requirement R1? If not, please explain why and provide specific suggestions for improvement. 1 Agree 0 Disagree Comments:<br>4. Requirement R2 of draft CIP-002-4 states, “Using the list of Critical Assets developed pursuant to Requirement R1, each Responsible Entity shall develop a list of associated Critical Cyber Assets performing a function essential to the operation of the Critical Asset. For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes. Each Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-4, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics”. The requirement then lists characteristics using the same text that is contained in the existing CIP-002-3 R3. Do you agree with the proposed Requirement R2? If not, please explain why and provide specific suggestions for improvement. 1 Agree 0 Disagree Comments: Although we agree with the proposed Requirement R2, We are concerned that the document “CIP-002-4 Cyber Security - Critical Cyber Asset Identification: Rationale and Implementation Reference Document” actually appears to provide more rationale and guidance on Critical Assets than Critical Cyber Assets.<br>5. Do you agree with the proposed implementation plan for the Version 4 standards? If not, please explain and provide specific suggestions for improvement. 1 Yes 0 No Comments:<br>6. Do you agree with the proposed revisions to the implementation plan for newly identified CCAs and Responsible Entities? If not, please explain and provide specific suggestions for improvement. 0 Yes 1 No Comments: We believe that it would be better to simply have a uniform 18 month |

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| | | | | implementation deadline for newly identified CCAs rather than have different timelines for different requirements. This will simplify reporting and streamline efforts to become fully compliant. We understand that nuclear timelines are subject to NRC requirements and the necessity of accomplishing some tasks only during refueling outages appropriately dictates a separate schedule for them. |

**Response**: Thank you for your comments.

Q2. Since there is no Requirement that applies to the Planning Coordinator or the Transmission Planner, it is not appropriate to include them in the Applicability section.

Item 1.1 – The guidance document posted by the SDT provides direction on the location issue. "Single plant location" refers to a group of generating units occupying a defined physical footprint and designated as an individual "plant" using commonly accepted generating facility terminology. Adjacent plants would be defined using the same criteria. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant.

Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."

Item 1.4 – A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." The SDT feels that these units must be classified as Critical Assets. It should be noted that not all blackstart generators are Blackstart Resources.

Item 1.8 – According to FAC-014-2, IROLs are established by Transmission Operators, Transmission Planners, and Planning Authorities. The Reliability Coordinator ensures that IROLs are established and are consistent with its methodology. The present wording is appropriate. This criterion has been changed to "Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

Item 1.9 – This criterion has been changed to "Flexible AC Transmission Systems (FACTS), at a single station or substation location, that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2 "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." It is not limited to offsite power requirements.

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| Item 1.12 – This criterion has been changed to "Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limit (IROL) violations for failure to operate as designed."<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot.<br><br>Q4. Thank you for your comments. The SDT will reexamine the guidance document.<br><br>Q5. Due to the limited scope of version 4, the SDT is only making conforming changes to the Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities. | | | | |
| Leonard Rentmeester | Wisconsin Public Service Corp. | 5 | Negative | WPS and UPPCO believe that a bright line criteria as proposed by the ballot will improve the reliability and safety of the BES. However, changes as provided by MRO's NSRS need to be incorporated into the proposed standard to eliminate the potential for arbitrary application and capricious enforcement of the standard. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Liam Noailles | Xcel Energy, Inc. | 5 | Negative | Please see our comments submitted during the concurrent comment period. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Edward P. Cox | AEP Marketing | 6 | Negative | Overall, AEP is supportive of the efforts and the general concepts of this draft; however, there are a few refinements that will enhance the requirements and remove ambiguity. AEP encourages the SDT to consider the items below in a future draft of the standard: AEP would contend that there are regional differences that would be relevant to determine a MW threshold for generators. We support the concept that was contained in the last draft that made the determination based on the capacity reserves. |

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| | | | | However, the prior language would need to be revisited to ensure that value was fixed for a period of time. In addition, requirement 2.2 uses the term control center (also used in attachment 1) that is not a NERC defined term. This will introduce ambiguity to implementation. There has been ongoing confusion regarding the difference between “control centers” and “control rooms.” We do not believe that a “control room” at a power plant or a substation would be considered a “control center.” There is language in the NERC Security Guideline for Electricity Sector: Identifying Critical Assets document that the SDT should consider and incorporate into the NERC Glossary. Net real power capability testing is defined in MOD-024 standards that have yet to be FERC approved. Furthermore, not all of the regions have defined the parameters for the capability testing. |
| **Response**: Thank you for your comments.<br><br>Item 1.1 - In prior versions we had wording about reserve sharing for the threshold. We received feedback that that wording was confusing, that the amount referred to in the reserve sharing was not a specific amount, and that the amounts changed daily. We did an informal survey of the regions, and we identified what the megawatt value of the reserve sharing would be for various groups. The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BAs in all regions.<br><br>At this time, the SDT is choosing not to add “control center” to the NERC Glossary. We feel defining this term under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. This term is used in other approved NERC standards already in effect.<br><br>CIP-002-4 does not require net real power capability testing. | | | | |
| Jennifer Richardson | Ameren Energy Marketing Co. | 6 | Negative | 1. (a) The proposed bright line criteria are not based on any studies or performance testing. (b) The proposed bright line criteria do not address proximity to load centers or the impact to system flows or voltages in those load centers. (c)Also, we believe that impact on the BES should be evaluated for the Critical Asset using the performance requirement contained in the existing mandatory standards. This would provide consistency between CIP-002 and other standards. In this regard, we suggest that for the facilities identified in the bright line criteria, perform powerflow and stability simulations to assess the impact to the BPS of the outage of these facilities, similar to the tests performed for TPL-003 and 004. If there is an impact (that is not meeting the performance criteria), then the facility is to be considered as critical. If there is no such impact, then the facility is not be considered as critical. If there is a concern for a multi-prong attack, then similar reliability assessment should be performed for such scenarios. (d)Further, the bright line criteria will include many |

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| | | | | more facilities as critical assets with minimal to no improvement to reliability and would require significant resource commitment to meet the proposed implementation schedule. 2. We offer some comments/suggestions and also have some questions/comments to the bright line criteria (Attachment 1): (a) The term “Facilities” should be changed to “substations and switchyards” throughout Attachment 1 as NERC glossary of terms include “lines” in the definition also. Is it SDT’s intention to include hundreds of miles of lines as critical asset? (b) The term “single station location” and “single plant location” used throughout Attachment 1 need to be defined to avoid confusion whether a single location mean one building or several buildings or stations within a defined geographical boundary or a fenced area. (c) Specific comments to Attachment 1 : 1.1 - Are there any reliability impact studies to support 1500 MW? We believe that several events larger than this number have occurred and the BES has performed as designed, without any loss of load, or significant impact on reliability. 1.6 - We disagree that all transmission facilities operated at 500 kV or greater are “critical”. Again, system studies should be conducted to take into account the impact that the asset has on the reliable operation of the BES before determining that an asset is a Critical Asset. 1.7 - We disagree that all transmission facilities that are operated at 300 kV or above and are interconnected with three or more transmission substations are “critical. System studies should be conducted to take into account the impact that the asset has on the reliable operation of the BES before determining that an asset is a Critical Asset. 1.8 - Wording for this criterion should be changed to “Transmission substations and switchyards that the Planning Coordinator or Transmission Planner designates that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL). This change would make this criterion consist with FAC-010/FAC-014. 1.12 - We believe that the criterion reads ok, but the rationale document for this criterion implies that purpose of SPS/RAS is to prevent disturbance that would result in excursion beyond IROLs. This may not be true in all cases. 1.13 - Wording for this criterion should be changed to “Common control system(s) capable of performing automatic load shedding of 300 MW or more with a single operation”. 1.15 - Same comments as for 1.1 above. 1.16 - Wording for this criterion should be changed to “Any additional assets owned by the Responsible Entity that the Responsible Entity deems appropriate to include.” 3. CIP-002-4, R2 : (a) The word “associated” could mean anything to do with a Critical Assets |

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| | | | | which is too broad of a term and needs to be defined to avoid confusion. (b)The phrase "could adversely impact the reliable operation" is unclear and vague. What magnitude of "adverse impact" should be considered? Also what is being defined as the Reliable Operation? This phrase should be more clearly defined, otherwise it could introduce different interpretations in the compliance audits. 4. The implementation plan is very confusing. |

**Response**: Thank you for your comments.

(1) The SDT and volunteer industry participants have expended considerable effort to develop consistent Critical Asset Identification approaches. The team endeavored to include work already required by other standards, and provide some constraints for an entity's assessment. These approaches, in their various iterations, have been presented to industry for review and comment. Significant feedback from the industry was the need to simplify the Critical Asset identification approach. We welcome your suggestions for improvement to the criteria. The Attachment 1 criteria were under development for CIP-010 when the team was asked to use the criteria for the basis of a new CIP Version 4 set of standards. The results of the recent NERC data request were used to assist the team in developing the criteria in Attachment 1. Bright-line criteria by its very nature may overreach in some areas and under-reach in others, with the end result being a more protected system on average.

The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. The SDT does not feel that a power flow analysis (impact-based or risk-based) may lead to a consistent application of the criteria, due to the numerous factors which can impact substation power flows. Such a study would need to be rigorously defined for the industry.

2. a) A transmission Line can be considered a Critical Asset if it meets the criteria in Attachment 1. It would then be evaluated for possible Critical Cyber Assets, which would be afforded the cyber security protection outlined in CIP-003 to CIP-009. It is not the Critical Asset that falls under CIP-003 to CIP-009, but the Critical Cyber Asset.

b) The guidance document posted by the SDT provides direction on the location issue. “Single plant location” refers to a group of generating units occupying a defined physical footprint and designated as an individual “plant” using commonly accepted generating facility terminology. Adjacent plants would be defined using the same criteria. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant.
c) Item 1.1 - In prior versions we had wording about reserve sharing for the threshold. We received feedback that that wording was confusing, that the amount referred to in the reserve sharing was not a specific amount, and that the amounts changed daily. We did an informal survey of the regions, and we identified what the megawatt value of the reserve sharing would be for various groups. The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BAs in all regions.

Items 1.6 and 1.7 – You propose to add the criteria that the Responsible Entity can determine through a risk-based evaluation that destruction, degradation or unavailability of certain assets will have no impact outside the local area and will not cause BES instability, separation, or cascading outages. The SDT does not feel that a power flow analysis (impact-based or risk-based) may lead to a consistent application of the

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| criteria, due to the numerous factors which can impact substation power flows.  Such a study would need to be rigorously defined for the industry.  We thank you for your proposal and will take it under consideration for future revisions.  Criterion 1.7 has been reworded to “Transmission Facilities operated at 300 kV or higher at stations or substations interconnected at 300 kV or higher with three or more other transmission stations or substations.”<br><br>Item 1.8 – This criterion has been changed to “Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.”<br><br>Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”<br><br>Item 1.15 –In the development of this criterion, the drafting team used 1500 MW as a bright-line for aggregate generation controlled based on the bright-line used in Part 1.1.  The drafting team specified a single Interconnection because it is more likely that the span of control of the generation control center may cross multiple BA or RSG areas or even regions and Interconnections.<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot.<br><br>(3) The phrase “adversely impact” limits the scope of the evaluation of Critical Cyber Assets to those that can affect the reliable operation of 1500MW or more of generation at a single plant location.<br><br>(4) The implementation plan is a modification of the implementation plan for version 3 of the CIP standards. | | | | |
| Brian Ackermann | Associated Electric Cooperative, Inc. | 6 | Negative | please review submitted comments |
| **Response**: Thank you for your comments.  Please refer to the response to comments document. | | | | |
| Brenda S. Anderson | Bonneville Power Administration | 6 | Negative | Please refer to BPA comments submitted during the formal comment period on 10/26/10 |
| **Response**: Thank you for your comments.  Please refer to the response to comments document. | | | | |
| Brenda Powell | Constellation Energy | 6 | Negative | Constellation Energy Commodities Group could vote affirmative in the next ballot if specific comments submitted on the Comment Form for Project |

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| | Commodities Group | | | 2008-06-Cyber Security 706 were successfully addressed (also submitted 11/3/10). |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Louis S Slade | Dominion Resources, Inc. | 6 | Negative | Dominion conceptually supports bright line criteria for determining critical assets. However, we cannot vote in favor at this time because we believe that changes are needed in Table 2 that recognize the implementation for infrastructure (physical and electronic security) should be equal to, or longer than, that required for training. We also believe that the bright line criteria for generation control center needs further effort. Please see more specific comments submitted using the NERC comment link for this project. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Larry W. Rodriguez | Entegra Power Services | 6 | Negative | There has been no consideration for "small shops" that will have an extreme financial impact. In addition, the only cyber security breach possibility is from Control Room employees, which is so very unlikly! |
| **Response**: Thank you for your comments. Cost is only one of many issues that must be considered in the cyber security of the BES.<br><br>The set of CIP cyber security standards (CIP-002 to CIP-009) is a holistic approach to cyber security protection that applies to both internal and external threats. | | | | |
| Terri F Benoit | Entergy Services, Inc. | 6 | Negative | Switchyards serving nuclear facilities should not be automatically classified as critical assets. The fact that a BES switchyard serves a nuclear facility should not in itself qualify the switchyard as a critical asset. While nuclear units and their support facilities may qualify as critical assets under a separate set of criteria, they should not automatically be designated as critical to the BES without some measure of the impact of the loss of the facility on BES reliability.<br>All blackstart units and associated cranking paths should not be automatically classified as critical assets. Blackstart units may be useful in the restoration of the BES following a large scale outage, but they are not necessarily essential to the reliability of the BES under normal operation. Blackstart units should not automatically be designated as critical to the BES without some measure of the impact of the loss of the facility on BES reliability. |

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| **Response**: Thank you for your comments.<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2, “Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.” Since these facilities were deemed so important that a NERC standard was written and adopted to clarify the issue, the SDT determined that this was adequate justification to include them as Critical Assets.<br><br>Item 1.4 – A Blackstart Resource is defined as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.” The SDT feels that these units must be classified as Critical Assets. It should be noted that not all blackstart generators are Blackstart Resources. | | | | |
| Richard L. Montgomery | Florida Municipal Power Agency | 6 | Negative | FMPA commends the SDT on making significant headway on the version 4 standards. However, there are significant additional improvement that should be made to make the criteria of Attachment 1 less arbitrary and that truly measures those assets that can have an Adverse Reliability Impact. Also, the standard is still unclear in several areas, such as how to identify CCAs at a substation if a substation is determined to be a CA that needs to be clarified. Please see FMPA's comments submitted through the formal comment process for more specific detail and proposed alternatives. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Thomas E Washburn | Florida Municipal Power Pool | 6 | Negative | Please see APPA's comments |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Paul Shipps | Lakeland Electric | 6 | Negative | Several additional improvement that should be made to make the criteria of Attachment 1 less arbitrary and that truly measures those assets that can have an Adverse Reliability Impact. Also, the standard is still unclear in several areas, such as how to identify CCAs at a substation if a substation is determined to be a CA that needs to be clarified. |
| **Response**: Thank you for your comments.<br><br>The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. | | | | |

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| Eric Ruskamp | Lincoln Electric System | 6 | Negative | Please review the comments submitted by the MRO's NERC Standards Review Subcommittee for LES' reasons for a negative ballot. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Brad Jones | Luminant Energy | 6 | Negative | Luminant Energy Company LLC (Luminant Energy) thanks the Standard Drafting Team (SDT) for their work on the NERC CIP Cyber Security Standards and for the opportunity to provide input into the standards development process. Although Luminant Energy has voted "Negative" on the current draft standard, Luminant Energy supports the SDT goal of completing the revision of CIP-002-4 by the end of December 2010, and believes with some modification to the Attachment 1 Criteria, the goal is still achievable.<br>Specifically, Luminant Energy is concerned that Criteria 1.3 has no defined basis for determining the reliability need of a generation Facility. As written, the Planning Coordinator or Transmission Planner could use any basis, or conversely, no basis, for designating a generation Facility as required for reliability purposes. For Criteria 1.8, 1.9, and 1.12, the SDT has appropriately used the violation of an Interconnection Reliability Operating Limit (IROL) as the basis for determining the reliability need of transmission Facilities. Luminant Energy believes this same basis is appropriate for application to generation Facilities in Criteria 1.3, and offers the following language for consideration by the SDT: 1.3 "Each generation Facility that the Planning Coordinator or Transmission Planner designates as required for reliability purposes, by demonstrating that the generation facility, if destroyed, degraded, misused or otherwise rendered unavailable, would violate one or more Interconnection Reliability Operating Limits (IROLs)." |
| **Response**: Thank you for your comments.<br><br>Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon." | | | | |
| Jeffrey M Keebler | Madison Gas and Electric Co. | 6 | Negative | The below are outstanding issues that the SDT should address before the next ballot. Comments are in line with the Unofficial Comment Form for Project 2008-06.<br>Q1: No, If a brightline is used, it removes all engineering analysis the entity is currently performing with the current CIP-002-3 methodology. This may |

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| | | | | bring in or remove assets for this Standard. A brightline approach may be useful to a smaller entity but may not be in the best interest to larger entities. The SDT should consider a brightline with a MW threshold for physical unit size or MW loads for control centers, see comments below.<br>Q2: Yes,<br>Criteria number 1.5; Based on the Rationale Document, please clarify that Facilities within the Cranking Paths will be assigned the Critical Asset identification up to the point where multiple path options exist.<br>Criteria number 1.13; Based on the Rationale Document, please clarify that the 300 MW level applies to a single common control system and not multiple like systems such as those installed for UFLS protection (multiple identical or similar individual, but independent, relays that may shed 300 MW's or more in aggregate, but individually shed less than 300 MW).<br>Criteria number 1.14; Based on the Rationale Document, every RC, BA, and TOP's control center, control system, backup control center and backup control system is Critical due to EOP-008. EOP-008-0 is the FERC approved Standard for US entities. The purpose of EOP-008-0 is: "Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable". The SDT quoted EOP-008-1 in the Rational Document, which is not FERC approved. The SDT needs to consider this when writing a continental wide Standard. The phrase in the Rationale Document: "While it is clear that the primary and all backup control centers operated by RCs, BAs, and TOPs must be designated as Critical Assets", is unjustified. Assuming a BA controls no critical assets qualified as such by other criteria, a BA that, in aggregate, controls relatively small amounts of real and/or reactive power clearly has less of an effect on reliability than a BA that controls relatively large amounts of such resources. Indeed, the fact that "size matters" is recognized by Criteria 1.1, 1.2, 1.6, 1.7, 1.13, and 1.15. Criterion 1.14 should be modified to recognize this conclusion by including relevant quantitative thresholds. Thresholds that were proposed in CIP-010 Criteria 1.13 and 1.14 would be reasonable. In any event, the thresholds for the BA control center or control system should be no more inclusive than those used to qualify the individual assets controlled by the BA. To complicate matters, presently there are 28 Local Balancing Authorities (LBA's) that are part of the Midwest ISO BA Area (JRO00001). These entities do not perform all the BA functional obligations as stated in the Rationale Document (the MISO BA performs the majority of BAL-001 through BAL-005). Furthermore, the scopes of operation of the LBA's span a wide range from small to large and |

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| | | | | few too many resources. This underscores the need to not assume that any BA (or LBA) that performs or supports any BA function or part of a BA function is necessarily critical to BES reliability. Please provide the analysis and justification to how these entities fit into the BA requirement as stated in 1.14. If it is the intent of the SDT to capture the generation within the balancing functions of a BA, the SDT has that covered by Criteria 1.15.<br>Q3: Disagree, While we agree with the general requirement of R1, we do not agree with certain aspects of Attachment 1 - Critical Asset Criteria, as discussed in responses to previous questions, above.<br>Q4: Agree<br>Q5: No, The implementation plan is clear on entities that either have in the past, identified they have CA's or have not ever identified CA's. The issue is present that what happens when an entity has only identified a control center as being a CA. But now they have identified a cranking path or Blackstart generator as being a CA. It is recommended that if non like items are identified as a CA, that the entity is given 24 months to become compliant. This will allow the entity enough time since they are now in an area that they may have not dealt with in the past.<br>Q6: No, See question 5. |

**Response**: Thank you for your comments.

Q1: The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology throughout North America.

Q2: Item 1.5 – The point where multiple paths exist in the Cranking Path is the step in the Transmission Operator's restoration plan per EOP-005-2 R1.5, "Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started," where the Transmission Operator can choose between the next Facilities on the BES to energize.

Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."

Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection." It is appropriate to

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| refer to an industry approved and NERC BOT approved standard in a guidance document, even if it has not been accepted at FERC.<br><br>Q3: Please refer to response to Q2 above.<br><br>Q4: Thank you.<br><br>Q5: The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset.<br><br>Q6: The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset. | | | | |
| Daniel Prowse | Manitoba Hydro | 6 | Negative | Please see comments submitted by Manitoba Hydro in the formal comment period. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Joseph O'Brien | Northern Indiana Public Service Co. | 6 | Negative | As NIPSCO understands the current set of CIP standards CIP-002-4 - CIP-004-4 & CIP-006-4 - CIP-009-4 it appears that each of the proposed standards needs to be corrected to modify the purpose section, which references the entire set of standards CIP-002-4 - CIP-009-4 when in reality CIP-005-4 does not yet exist and is not being balloted in at this time.<br>In addition CIP-003-4 R1, R2 make reference to the entire set of version 4 standards, which would also include the unapproved CIP-005-4. The unapproved CIP-005-4 is specifically identified as a compliance requirement within CIP-006-4 R2.2 and CIP-007-4 R7. The primary concern is that the industry is being asked to ballot on a set of standards that references a standard that does not yet exist. There is also concern for future applicability concerns in regards to effective dates with CIP-005-4 and implementation date overlap conditions that could occur when CIP-005-4 goes to ballot again and potentially get approved. This is a straightforward correction to the version 4 standards and would most easily be resolved by proposing a new CIP-005-4 that simply updates the versioning information within the standard in the same approach that was taken for CIP-003-4 - CIP-004-4 & CIP-006-4 - CIP-009-4. In CIP-002 Version 4 under Applicability we're not sure why NERC is listed. At the very least this should |

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| | | | | be replaced by ERO however it's still not clear how this entity fits in with the Functional Model. |
| **Response**: Thank you for your comments.<br><br>The following information was provided with the posting of the CIP Version 4 standards:<br><br>*(CIP-005-4 - Cyber Security — Electronic Security Perimeter is posted separately, with a set of proposed revisions for Urgent Action under Project 2010-15. If CIP-005-4 is not approved as an Urgent Action, it will be returned to this set of CIP standards.)*<br>As for listing NERC in the Applicability section, NERC has historically been listed in this section for the CIP body of standards. | | | | |
| Alan R. Johnson | NRG Energy, Inc. | 6 | Negative | Pertaining to CIP-002-4 R1, the following need to be addressed in Attachment 1:<br>1.1 - Add capacity factor as a qualifier for exclusion below an established low threshold.<br>1.3 - Mandate coordination/approval process between the Transmission Planner and entity that have been designated critical by the Transmission Planner. These classifications and approvals need to take into consideration 5 year forecasts for planning and budgeting purposes..<br>1.5 - TOP needs to define the cranking path in restoration plan to the affected entities to adequately secure these restoration paths..<br>1.9 - Please explain FACTS - need definition<br>1.10 - Need coordination between TOP & GO to identify critical assets.<br>1.15 - How is the 1500 MW aggregate determined? Is it an aggregate of generator name plates or the sum of controllable megawatts between a unit's high and low limits?<br>General: Attachment 1 needs to have defined terms for capability, plant, control center Requirement 2 needs to clarify the following items:<br>1) Need Clarification on routable path, discrete links and serial connections as it pertains to CIP-002-3 R3: Is a device considered to communicate outside the ESP using routable protocol if ANY portion of the communications path uses routable protocol?<br>2)Need clarification concerning shared assets. Does it mean shared between a single device or same device on a network?<br>3)R2 states that only shared cyber assets for a group of generating units at a single location identified in Attachment 1 criteria 1.1, namely the 1500 MWs brightline, that could impact reliable operation, should be considered. Does this cyber asset identification only include assets meeting criteria 1.1 and therefore exclude any cyber assets utilized for reliable operation of a designated critical asset such as a single blackstart resource? Please |

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| | | | | provide clarification in this requirement. |
| **Response**: Thank you for your comments.<br><br>Item 1.1 – The SDT debated whether to include capacity factor in this criterion. The reason we ultimately chose not to include capacity factor is twofold. First, there is no consistent method to select an appropriate capacity factor, and low capacity factor units may be critical to the system at peak load conditions. Second, there was concern that some units might fall below the line during major outage periods, taking them off the Critical Asset list one year and putting them back on the list the next year.<br><br>Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."<br><br>Item 1.5 – Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."<br><br>Item 1.9 – FACTS is defined by IEEE as "Alternating Current Transmission Systems incorporating power electronics-based and other static controllers to enhance controllability and power transfer capability."<br><br>Item 1.10 – The assets would be identified by the asset owners. It is agreed that communication between GOs and TO/TOPs will be required.<br><br>Item 1.15 – This is the aggregate highest rated net Real Power capability output of all generation under dispatch/control.<br><br>At this time, the SDT is choosing not to add "capability," "plant," or "control center" to the NERC Glossary. We feel defining these terms under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. These terms are used in other approved NERC standards already in effect.<br><br>The requirement refers to shared cyber assets that can have a reliability impact on the group of generating units. This qualifier only includes Critical Assets identified in criterion 1.1. | | | | |
| James D. Hebson | PSEG Energy Resources & Trade LLC | 6 | Negative | Please see PSEG companies' comments filed separately. The PSEG Companies will change the vote to affirmative if the comments are adequately addressed by the drafting team. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Trent Carlson | RRI Energy | 6 | Negative | Criteria 1.6 and 1.7 are arbitrary without clarification and in relation to Criteria 1.10. Suggest adding the following clarification to the end of Criteria 1.6 and 1.7: ", unless the Transmission Facilities only provide the |

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| | | | | generation interconnection required to directly connect generator output to the transmission system."<br>o Criteria 1.6, as modified, should read as follows: "Transmission Facilities operated at 500-kV or higher, unless the Transmission Facilities only provide the generation interconnection required to directly connect generator output to the transmission system."<br>o Criteria 1.7, as modified, should read as follows: "Transmission Facilities operated at 300-kV or higher at stations interconnected at 300-kV or higher with three or more other transmission stations, unless the Transmission Facilities only provide the generation interconnection required to directly connect generator output to the transmission system." |
| **Response**: Thank you for your comments.<br><br>Item 1.6 –The drafting team believes all Transmission Facilities operated at 500 kV or higher do not require any further qualification for their role as components of the backbone on the Interconnected BES.<br><br>Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Asset a Transmission Facility operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations. | | | | |
| Mike Hummel | Salt River Project | 6 | Negative | SRP believes that a bright line assessment methodology for determining Critical Assets is not in the best interest of reliability. This is especially true in the designation of substations and generating facilities. The attributes of these stations and their unique impact on Bulk Electric System reliability must be taken into account. There are several terms and phrases used within Requirement 2 of the proposed Standard that need to be better defined to eliminate ambiguity. These terms are: 1) essential to the operation of the Critical Asset, 2) adversely impact the reliable operation needs to be defined; and, 3) within 15 minutes. We believe the CIP-002-4 implementation plan for newly identified Critical Assets and associated Critical Cyber Assets provides inadequate time. SRP suggests the implementation timeframe be extended to 30 months after the effective date of the Standard. |
| **Response**: Thank you for your comments.<br><br>The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. | | | | |

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| The phraseology you are concerned about (annual) exists in the existing CIP-002-3 standard. The SDT expects this phraseology to be resolved in the next version<br><br>Thank you for your comment. The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset. | | | | |
| Marjorie S. Parsons | Tennessee Valley Authority | 6 | Negative | Tennessee Valley Authority (TVA) appreciates the opportunity to comment on this CIP-002-4 draft. We fully support the standards development process and all the hard work and commitment by the drafting team members. For this draft, we have the following concerns which moved us to cast a Negative vote.<br>Q1: Yes; no comment<br>Q2: 1.4. Each Blackstart Resource identified in the Transmission Operator's restoration plan. The language appears to require us to designate “Each” component in the System Restoration plan as CA. Because we currently include at least 2 paths for black start of every generation plant in the system, the proposed language would require the extension of CA designation to a large number of components which otherwise would not be included by other criteria. The flexibility provided by our robust transmission infrastructure and the large number of black start capable plants serves to ensure reliable operation of the BES, but designating as a CA each component that could participate in the total paths possible doesn’t seem consistent with the intent of the standard. Recommendation: Revise language to allow entities to limit CA designation to those components participating in the primary black start path.<br>1.10. Transmission Facilities providing the generation interconnection required to directly connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3. There isn’t a clear definition of the term “directly connected.” Without this definition there are many way to interpret this requirement. Is this language meant to describe a facility where the substation is co-located with a generation facility? Also, does the language this mean total loss of substation or only partial? Recommendation: For the purpose of this standard revise language to clearly define “directly connected.”<br>Q3: Yes; no comment<br>Q4: Yes; no comment<br>Q5: abstain |

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| **Response**: Thank you for your comments.<br><br>Item 1.4 – The SDT considered using the word “primary”, but ultimately rejected it as it is not a defined NERC Glossary term, nor is it used in EOP-005-2. A Blackstart Resource is defined as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.” EOP-005-2 R1.4 states that the restoration plan must include “Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.” The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources.<br><br>Item 1.10 – The intent is to ensure the availability of Facilities necessary to support those generation Critical Assets. Any transmission Facility that the loss of which would result in the loss of a Critical Asset identified in criterion 1.1 or 1.3 would need to be classified as a Critical Asset. That might include the partial or total loss of a substation. | | | | |
| David F. Lemmons | Xcel Energy, Inc. | 6 | Negative | Please see our comments submitted during the concurrent comment period. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| James A Maenner | | 8 | Negative | The Applicability for CIP-002-4 seems to cast a wide enough net to find some entity responsible for determining assets as critical. The problem is that most of those listed in Section 4 have no ability or expertise to study or determine the criticalness of an asset on the BES. Ultimately, the identification of critical assets should be the responsibility of the Planning Coordinator or Transmission Planner with a notification (and explanation) to the critical asset owner who then creates the list of associated Critical Cyber Assets and performs all necessary steps to satisfy Standards CIP-003 through 009.<br>I noticed NERC and the RE on the list. Is there a process for independent monitoring and auditing of those entities?<br>Bullet 1.8 of Attachment 1 should identify the TP or PC as responsible. |
| **Response**: Thank you for your comments.<br><br>The burden for identifying Critical Assets is with the Responsible Entity that is the asset owner. This is consistent with FERC order 706. | | | | |

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| The Compliance Monitoring and Enforcement section addresses NERC and the RE.<br><br>Item 1.8 – According to FAC-014-2, IROLs are established by Transmission Operators, Transmission Planners, and Planning Authorities. The Reliability Coordinator ensures that IROLs are established and are consistent with its methodology. | | | | |
| Nicholas Lauriat | Network & Security Technologies | 8 | Negative | The term "risk-based assessment methodology" still appears in the last sentence of R3. |
| **Response**: Thank you for your comments. That reference will be removed in the posting for the next ballot. | | | | |
| Jim R Stanton | SPS Consulting Group Inc. | 8 | Negative | Critical Asset Criteria 1.3 states: "Each generation Facility that the Planning Coordinator or Transmission Planner designates as required for reliability purposes." Here, reliability purposes is not defined so the criteria is intrinsically ambiguous, which will likely trigger rounds of interpretation requests. Also, Transmission Planners and Planning Coordinators are not uniformly independent. Non-independent entities, through the application of this criteria, could designate selected competitors as "required for reliability purposes" and do so, as written, without supporting studies and independent affirmation of the designation. Hence, the dramatic costs of compliance with CIP standards will be imposed on competitors, increasing their costs and blunting competition. This criteria fails the SAR condition that states: "A reliability standard shall not give any market participant an unfair competitive advantage." This criteria clearly gives Transmission Planners and Planning Coordinators an unfair competitive advantage. If the criteria is to remain in subsequent revisions, then it should also say that such designations will be supported by independently confirmed studies showing the need for the reliability designation, and subsequent exposure to the CIP standards. |
| **Response:** Thank you for your comments.<br><br>Item 1.3 – The burden for identifying Critical Assets is still the Responsible Entity that is the asset owner. There is no burden or obligation placed on the Planning Coordinator or Transmission Planner to designate any unit as needed for reliability. This criterion has been reworded to “Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.” If it is determined through system studies that a unit must run in order to preserve the reliability of the BES, then that unit must be classified as a Critical Asset. If an entity feels that they have an asset that has been unjustly classified as “required for reliability reasons,” there are appeals processes that can be used. | | | | |
| James D Burley | Midwest Reliability | 10 | Negative | We do not see any added value in Requirement R1. This requirement requires the reponsible entity to develop a list of its critical assets and then |

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| | Organization | | | from this list, requriement R2 requires the responsible entity to develop a list of critical cyber assets for each identified critical asset. We believe this methodology is flawed. A critical cyber asset may exist at a location not deemed a critical asset.We believe this is a serious flaw in the current standard and the suggest revision does nothing to remedy it.We recommend the drafting team write the requirment so the registered entities simply identify critical cyber assets. |
| **Response**: The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues. | | | | |
| Larry D Grimm | Texas Reliability Entity | 10 | Negative | (1) Texas RE supports the addition of specific criteria for identifying Critical Assets, as shown in Attachment 1 of this draft.<br>(2) In R3, the reference to “risk-based assessment methodology” is a carry-over from the prior version of CIP-002, and it no longer applies in this version of the standard.<br>(3) In Attachment 1, items 1.14 and 1.15, the term “control center” should be defined or more specifically characterized in order to provide guidance as to exactly what facilities are included.<br>(4) In section 1.3, Compliance Monitoring and Enforcement Processes, “Periodic Data Submittal” should be added to the list, because it is a process that will be useful in monitoring this revised standard. |
| **Response**: Thank you for your comments.<br><br>1) Thank you.<br>2) That reference will be removed in the posting for the next ballot.<br>3) At this time, the SDT is choosing not to add “control center” to the NERC Glossary. We feel defining this term under this proposed version of the Standard would have far-reaching impacts beyond the scope of CIP-002-4 to CIP-009-4. This term is used in other approved NERC standards already in effect.<br>4) Thank you for your comments. At this time the SDT is not choosing to add periodic data reporting to the CIP body of standards. | | | | |
| Louise McCarren | Western Electricity Coordinating Council | 10 | Negative | We recognize and appreciate the efforts of the drafting team in developing a bright line set of criteria for identifying Critical Assets. This approach will lead to more uniformity and consistency across the continent in the identification of Critical Assets. However, some stakeholders have indicated that the bright line Criteria included in Attachment 1 of CIP-004-2 will lead to fewer Critical Assets being identified than their initial methodology that was required by older versions of CIP-002. We encourage the drafting team to review the thresholds for identifying Critical Assets to ensure that they are appropriate. We also believe a similar effort in identifying a bright |

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| | | | | line criteria for Critical Cyber Assets is necessary. Stakeholders have commented regarding the lack of clarity in the language of Requirement 2 of CIP-002. The language "essential to the operation of the Critical Asset" is subjective and could lead to the same lack of uniformity and consistency in identifying Critical Cyber Assets that drove the changes in identification of Critical Assets. A lack of a uniform and consistent identification of Critical Cyber Assets may prevent the desired level of reliability and security. |
| **Response**: Thank you for your comments.<br><br>While some entities may have a few assets fall off of its Critical Asset list, it is expected that overall more BES assets in North America will be classified as Critical Assets.<br><br>The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The team deliberately limited the scope of changes in this interim standard to minimize the impact on the industry while addressing the identified consistency issues.<br><br>The phraseology you are concerned about exists in the existing CIP-002-3 standard. The SDT expects to correct this phraseology in the next version. | | | | |
| Jason Shaver | American Transmission Company, LLC | 1 | Affirmative | ATC agrees the implementation schedule in general, should allow for sufficient time (18 months from effective date; 24 months from FERC approval date) for Category 2 entities to become compliant with CIP-003 through CIP-009. However, we suggest an extension should be allowed for good cause if approved by the Regional Entity. |
| **Response**: Thank you for your comments.<br><br>The suggested modification proposes an exception process to a mandatory standard, and we refer to the discussion on technical feasibility exceptions in the FERC Order. Specifically, the oversight framework which must be in place is summarized in paragraph 222. | | | | |
| John J. Moraski | Baltimore Gas & Electric Company | 1 | Affirmative | Affirmative ballot is contingent on successfully addressing specific comments submitted on the Formal Comment Form for Project 2008-06 Cyber Security 706. |
| **Response**:Thank you for your comments. Please refer to the response to comments document. | | | | |
| Chang G Choi | City of Tacoma, Department of Public Utilities, Light Division, dba | 1 | Affirmative | Tacoma Power has submitted comments during the comment period for Version 4 of the CIP standards. If there is a subsequent future ballot for Project 2008-06, consideration of all submitted comments need to be reflected in such ballot. |

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| | Tacoma Power | | | |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Christopher L de Graffenried | Consolidated Edison Co. of New York | 1 | Affirmative | 1. New Requirement R1: We request an explicit definition of "annual." In addition, it is not clear whether the "update as necessary" applies to updates to the list during the annual review. The language should be clarified to more definitely express the "update as necessary" to be applicable to the list during the annual review. 2. New Requirement R2: In addition, there is no reason for the parenthetical with the specific inclusion of nuclear generation. It should be removed. 3. Attachment 1/Requirement R2: We suggest the removal of "control system" and "backup control system" in Attachment 1, Part 1.14. These systems should be identified as part of new Requirement R2, Critical Cyber Asset Identification. 4. Attachment 1: Part 1.3 is extremely broad and is under defined. Either delete it or provide additional specificity delineating the limited range of circumstances when a PC or TP may designate a facility as critical. 5. Attachment 1: Part 1.10 uses the phrase "the loss of the assets" without describing the relevant time period. Are these assets losses for a few cycles, for a few minutes, for a few hours or for a few days? We recommend that the conclusion of Part 1.10 state "...would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3 for a period of xx hours (e.g., 24 hours) or more." 6. Implementation Plan: Agreed, so long as an Entity can have access to an exception process with an implementation plan to request additional time due to a large increase in identified assets, without a self-reported violation, within an implementation schedule. |
| **Response**: Thank you for your comments.<br>1) The phraseology you are concerned about exists in the existing CIP-002-3 standard. The SDT expects to correct this phraseology in the next version.<br>2) The parenthetical statement about nuclear generation comes from Attachment 1 criterion 1.1.<br>3) Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the | | | | |

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| functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."<br>4) Item 1.3 – This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."<br>5) The phrase "loss of assets" is not limited to any period of time. A trip and a 24 hour outage would both apply.<br>6) Thank you for your comments. | | | | |
| Robert Martinko | FirstEnergy Energy Delivery | 1 | Affirmative | FirstEnergy appreciates the CIP Standard Drafting Team's (SDT) careful consideration of our and other stakeholder feedback during prior comment periods and the SDT's decision to develop the CIP-002-4 bright-line standard. The development of CIP-002-4 and continued use of the CIP-003 through CIP-009 standards brings needed industry consistency in Critical Asset determinations while appropriately building upon prior industry efforts of implementing the CIP standards. FirstEnergy supports CIP-002-4 and is voting AFFIRMATIVE for the standard but believes changes are needed to better clarify Attachment 1. In our view, some of the criteria are vaguely written and subject to interpretation - specifically criteria 1.8 and 1.11 - and we offer suggestions for improving expectations and compliance certainty. Additionally, we suggest less substantive changes to criteria 1.5 and 1.14 for clarity and consistency. Lastly, we encourage the SDT to reconsider its Implementation Plan for the CIP version 4 standards. The Implementation Plan is a 15 page document which is overly complex and difficult to understand. Please refer to FE's comments submitted through the parallel comment period for suggestions for improvement and simplification. The following are FirstEnergy's proposed Attachment 1 changes:<br>1) Criterion 1.8 currently states "Transmission Facilities at a single station location that, if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs)." Clarity needed: A.) It is not evident who is responsible for identifying the applicable transmission facilities covered by 1.8. B.) Item 1.8 should rely on review/analysis that is regularly performed by industry in meeting other NERC reliability standards. Item 1.8 should be based on IROL determinations made from planning horizon studies and information communicated to responsible entities via FAC-010/FAC-014. C.) A possible misinterpretation of Attachment 1, Item 1.8 is that it is intended to review a complete loss of substation. However the words say "Transmission Facilities at a single station location ..." not all transmission facilities at a |

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| | | | | single substation location. Based on the above items, FirstEnergy proposes the following for item 1.8: “1.8. Transmission Facilities designated by the Planning Coordinator or Transmission Planner that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL).” The Planning Coordinator and Transmission Planner determine and communicate IROLs in the planning time horizon per NERC reliability standard FAC-014. The subject Transmission Facilities are the contingency Transmission Facilities communicated by the PC and TP per requirement R5 of FAC-014. The 1.8 criterion should not appear to require any new study or analysis by the TP or PC.<br>2) Criterion 1.11 currently states “Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements” Clarity needed: The term “essential” is vague and open to interpretation. FE suggests that the SDT focus on Transmission Facilities identified in Nuclear Plant Interface Requirements identified as providing offsite power supply for nuclear plant safety requirements. We propose the following change for 1.11: “1.11 Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements.”<br>3) Criterion 1.5 currently states “The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist.” FirstEnergy suggests replacing the word “multiple” with “two or more” for clarity.<br>4) Criterion 1.14 currently states “Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator.” FirstEnergy suggests removing the text “control system” and “or backup control system” for consistency to criteria 1.15. If the intent is to ensure coverage of offsite data centers or telecommunication centers that support the “control center” then the SDT should provide a separate criterion in Attachment 1. To extend coverage of 1.14 and not 1.15 is inconsistent and the use of the phrase “control system” is vague. |

**Response**: Thank you for your comments.

Item 1.8 – This criterion has been changed to “Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits

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| (IROLs) and their associated contingencies."<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2 "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." It is not limited to offsite power requirements.<br><br>Item 1.5 – This criterion has been reworded to "The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist as identified in the Transmission Operator's restoration plan."<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."<br><br>The SDT has simplified the Implementation Plan to reference the Effective Date of CIP-002-4 through CIP-009-4 which is 8 calendar quarters after regulatory approval. | | | | |
| Michael Moltane | International Transmission Company Holdings Corp | 1 | Affirmative | ITC Votes "Affirmative" on this ballot as we consider it a great improvement over the existing Standard. However, we do have some concerns. Specifically, new CIP-002-4 R2 Critical Cyber Asset Identification- The revisions made are introducing confusion while only identifying the inclusion of Cyber assets with delimited (arbitrarily) time for impact: "For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes." Either a new qualification and characteristic of Critical Cyber Assets is created or the existing characteristics shall be updated to explicitly address the type of Cyber Asset. |
| **Response**: Thank you for your comments<br><br>The requirement refers to shared cyber assets that can have a reliability impact on the group of generating units. This qualifier only includes Critical Assets identified in criterion 1.1. The 15-minute threshold is intended to include only those assets at generating units affecting real-time operations. This qualifier is particularly important to a generating plant because several systems (i.e. a fuel-handling system) may be essential after a longer period of time but do not necessarily involve real-time reliability impact. We have updated the wording of R2 to clarify the meaning of this phrase. | | | | |

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| Michael Gammon | Kansas City Power & Light Co. | 1 | Affirmative | The bright-lines established by the proposed standard have not been established with a strong engineering basis and do not necessarily reflect a true measure of reliability impact to the bulk electric system. It is recommended to develop a process to determine a true reliability assessment and adjust the bright-line proposed here to a deliberate and supportable definition. |
| **Response:** Thank you for your comment. The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology. | | | | |
| Martyn Turner | Lower Colorado River Authority | 1 | Affirmative | 1.5. The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist. If a multiple path option exists from the Black Start Resource to a Next Start unit, does a Critical Path have to be designated? To clarify, the criteria states “The Facilities comprising the Cranking Paths... up to the point where multiple path option exist.” If a transmission owner/operator has multiple paths originating directly at the Black Start Resource, either path could be used as a cranking path. Therefore, neither path would be considered critical. Could this be clarified?<br>1.7. Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. 1) Does this includes radial interconnections? This is a question because a 345 kV station could be interconnected to 3 other stations, but one of the interconnections could be a radial 345 kV line connected to a generator. 2) Is there a distance requirement for the interconnection? This is a question because a 345 kV station could be interconnected to 3 other stations, but one of the interconnections could be a 345kV bus connected to another station a few feet away. These questions need to be resolved; otherwise a negative may be considered for these standards in the future ballots. |
| **Response**: Thank you for your response<br><br>Item 1.5 – The point where multiple paths exist in the Cranking Path is the step in the Transmission Operator’s restoration plan per EOP-005-2 R1.5, “Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started,” where the Transmission Operator can choose between the next Facilities on the BES to energize. Based on your example, neither path would be identified as a Critical Asset. | | | | |

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| Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Asset a Transmission Facility operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations. There is no distance requirement in the criterion. | | | | |
| Saurabh Saksena | National Grid | 1 | Affirmative | 1. First, the proposed standard will lead to an improvement in reliability for entities that are either newly registered or envision new assets coming under their CIP purview. However, based on a preliminary assessment, National Grid anticipates minimal impact of the proposed revisions for National Grid's registered entities. Because National Grid's current risk-based methodology for identifying critical assets is similar to the bright-line criteria proposed in the revision for CIP-002, National Grid's current critical asset list is very inclusive Hence, from National Gird's perspective, the proposed standard will not lead to a significant improvement in reliability with regard to National Grid's facilities because it will not result in a significant increase in the number of assets identified as critical. Second, the proposed revision to the standard aims to replace the existing risk-based methodology with the new bright-line criteria. However, R3 of the proposed standard (reproduced below) still refers to the risk-based methodology. National Grid proposes to delete the reference to the risk-based methodology in R3 for consistency and to reduce the possibility of confusion on the part of senior managers attempting to comply with R3.<br><br>2. National Grid proposes to include the class of assets - generation, transmission, and control centers against each criterion in attachment 1. This will help entities to clearly identify which requirements fall under different classes of assets. For example - 1.5 The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist. (Generation, transmission)<br><br>3. The standard clearly mentions the documentation required to comply with CIP-002-4 which includes - list of Critical Assets as specified in R1, list of Critical Cyber Assets as specified in R2, and approval records of annual approvals as specified in R3. However, in the Guidance document, Page 7, bullet point 2, second sentence, it states the following - "...Responsible Entity should document all criteria that qualify this asset as a Critical Asset..." National Grid recommends that the drafting team clarifies the |

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| | | | | documentation requirements to avoid such discrepancies. If the standards drafting board expects entities to document, and retain documentation, of the criteria that supports the categorization of critical assets, this should be explicitly required by the standard. As the proposed standard is written, the only documentation registered entities must create and retain is the actual list of the assets. |
| **Response**: Thank you for your comments.<br><br>1) Prior to the next round of balloting, the reference to risk-based methodology in R3 will be removed.<br>2) The Applicability section of the standard specifies to which NERC Registered Entities the standard applies. All Requirements apply to all Entities listed in the Applicability section.<br>3) The guidance document has been updated to delete the reference. | | | | |
| David H. Boguslawski | Northeast Utilities | 1 | Affirmative | Regarding CIP-002-4 Attachment 1, please consider the following: CIP-002-1 Attachment 1 criterion 1.3 reads: “Each generation facility that the planning coordinator or transmission planner designates as required for reliability purposes”. We believe that as stated, this criterion (1.3) is subject to interpretation. Specifically, “for reliability purposes” can be interpreted as “must-run” units, required for black start (although that could be duplicative to criteria 1.4), or as any generator containing BPS elements. Suggest more clearly defining “for reliability purposes” or restating the criterion. The terminology used in the recent NERC data request appeared to be clearer - that is: “Any generation facility that the planning coordinator identifies as Reliability ‘must run’ assigned units”. CIP-002-1 Attachment 1 criterion 1.10 reads: “Transmission facilities providing the generation interconnection required to directly connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3.” We believe that as stated, this criterion (1.10) could be interpreted to mean not only generators owned by the responsible entity but also those not owned by but interconnected to the Transmission Owner’s system. Clarification of criterion 1.3 should serve to clarify criterion 1.10 as well. |
| **Response**: Thank you for your comments.<br><br>Item 1.3 – This criterion has been reworded to “Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.”<br><br>Item 1.10 – The SDT agrees that not only generators owned by the Responsible Entity but also those not owned by but interconnected to the | | | | |

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| Transmission Owner's system are subject to criterion 1.10. | | | | |
| Pawel Krupa | Seattle City Light | 1 | Affirmative | Seattle City Light Subject Matter Expert (SME) supports the changes proposed for CIP-002-4 and recommends a "yes" vote despite imperfections with the language of draft Appendix A. SME recommends comments in the hope that the language yet will be clarified. Specifically, Seattle City Light commends the change to a "bright-line" approach to identifying Critical Assets as proposed in draft CIP-002-4. The use of nationwide criteria reasonably captures as Critical Assets the large generating units and high voltage transmission facilities essential to the reliable operation of the North American Bulk Power System. The flexibility afforded individual Planning Coordinators and Transmission Planners to specify additional facilities as Critical Assets important to local reliability furthers the objective of Bulk Power System reliability by allowing some smaller generating units and transmission facilities to be called out as Critical Assets without drawing in all assets of a certain size that are not critical elsewhere. These changes are consistent with Seattle City Light's philosophy towards Critical Assets, which always has been about stepping up and acknowledging the importance of identifying and protecting all Critical Assets essential to the reliability of the bulk power system. Ultimately CIP-002-4 as proposed promises to benefit the electricity industry, consumers, and North America by improving reliability through a certain and consistent application of the Critical Asset identification process. That said, Seattle City Light SME expresses concern that imperfections in the language of draft CIP-002-4 may frustrate its promise of bringing Critical Asset certainty and consistency. Imprecise language has been a recurring problem all throughout the short life of the NERC Mandatory Reliability Standards. Unnecessary compliance difficulties, tortured interpretations, and wasteful efforts have resulted. Lack of care with language threatens the existing regulatory regime by fostering distrust among industry, regulators, government, and the public at large. As such the comments below are offered as potential corrections to the details of draft and not as reflecting on the "bright-line" approach of proposed CIP-002-4.<br>1. Requirement 2 of draft CIP-002-4 states, "For each group of generating units (including Nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable |

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| | | | | operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes.” Seattle City Light is finding the term ‘shared Cyber Assets’ unclear and suggests clarification as follows: “For each group of generating units (including Nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those Cyber Assets networked to a system that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes.”<br>2. Critical Asset criterion 1.7 of CIP-002-4, Appendix A, identifies as Critical Assets “Transmission facilities operated at 300 kV or higher at stations interconnected at 300 kV of higher with three or more other transmission stations.” Seattle City Light agrees with Lower Colorado River Authority that additional detail is needed about the nature of the specified interconnections. In particular, questions exist as to type (what about a radial line connected to a generator-does it count?) and distance (does a high-voltage bus count if connected to another substation a dozen feet away?).<br>3. Critical Asset criterion 1.13 indicates that “Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes” are Critical Assets. Seattle City Light concurs with the assessment of APPA and others that this wording may inadvertently include any SCADA system that controls 300 MW or more of load (and thus has ‘capability’ to shed it), and recommends wording similar to item 1.11 of draft CIP-010-1, “BES elements that perform automatic aggregate load shedding of 300 MW or more within 15 minutes.” |

**Response**: Thank you for your comments.

1) Requirement R2 has been changed to clarify the issues presented.
2) Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Asset a Transmission Facility operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations. There is no distance requirement in the criterion.
3) Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”

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| Allen Klassen | Westar Energy | 1 | Affirmative | Westar shares and would echo many of the concerns already expressed by other entities, but is casting an affirmative vote to move this process forward. |
| **Response**: Thank you for your comments. | | | | |
| Peter T Yost | Consolidated Edison Co. of New York | 3 | Affirmative | 1. New Requirement R1: We request an explicit definition of "annual." In addition, it is not clear whether the "update as necessary" applies to updates to the list during the annual review. The language should be clarified to more definitely express the "update as necessary" to be applicable to the list during the annual review. 2. New Requirement R2: In addition, there is no reason for the parenthetical with the specific inclusion of nuclear generation. It should be removed. 3. Attachment 1/Requirement R2: We suggest the removal of "control system" and "backup control system" in Attachment 1, Part 1.14. These systems should be identified as part of new Requirement R2, Critical Cyber Asset Identification. 4. Attachment 1: Part 1.3 is extremely broad and is under defined. Either delete it or provide additional specificity delineating the limited range of circumstances when a PC or TP may designate a facility as critical. 5. Attachment 1: Part 1.10 uses the phrase "the loss of the assets" without describing the relevant time period. Are these assets losses for a few cycles, for a few minutes, for a few hours or for a few days? We recommend that the conclusion of Part 1.10 state "...would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3 for a period of xx hours (e.g., 24 hours) or more." 6. Implementation Plan: Agreed, so long as an Entity can have access to an exception process with an implementation plan to request additional time due to a large increase in identified assets, without a self-reported violation, within an implementation schedule. |
| **Response**: Thank you for your comments.<br><br>1) The phraseology you are concerned about exists in the existing CIP-002-3 standard. The SDT expects to correct this phraseology in the next version.<br>2) The parenthetical statement about nuclear generation comes from Attachment 1 criterion 1.1.<br>3) Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which | | | | |

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| states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."<br>4) Item 1.3 – This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."<br>5) The phrase "loss of assets" is not limited to any period of time. A trip and a 24 hour outage would both apply.<br>6) Thank you for your comments. | | | | |
| Henry Ernst-Jr | Duke Energy Carolina | 3 | Affirmative | Duke Energy appreciates the drafting team's work, and offers the following comments, which are also being submitted via the comment form:<br>1. We agree that the revised CIP-002-4 will lead to an improvement in reliability. However, CIP-003 through CIP-009 need modifications other than just changing the revision numbers, as evidenced by numerous interpretation requests and general confusion in the industry. While we understand that the plan is to complete those modifications in 2011, industry will be adding numerous Critical Assets and Critical Cyber Assets due to these revisions to CIP-002. Applying the current versions of CIP-003 through CIP-009 to numerous additional Critical Cyber Assets compounds the difficulty of maintaining compliance without more clear direction.<br>2. CIP-002-4 Attachment 1 criteria need further clarification.<br>a. 1.1 - Consistent with Criteria 1.8 and 1.9, this criterion should be conditioned by adding the phrase "unless planning studies are available to demonstrate that the loss of generation does not cause violation of one or more Interconnection Reliability Operating Limits (IROLs)." Related to the generation loss impact on Interconnection frequency and resource adequacy, Duke Energy disagrees with the arbitrary selection of the generation loss MW amount for the following reasons: o System inertia and frequency response factor into potential impact a generation loss could have on Interconnection frequency, and are different for each Interconnection. A 1,500 MW loss in the Eastern Interconnection is much less significant in terms of the initial frequency deviation than a similar loss within any other Interconnection. o The limit fails to recognize the options available to the Balancing Authority to restore its balance within the existing criteria of the NERC reliability standards. For example, recovery from the loss of 1,500 MW within a 5,000 MW Balancing Authority may be quite different than recovery from a 1,500 MW loss within a 135,000 MW Balancing Authority in the Eastern Interconnection. PJM alone is about |

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| | | | | twice the size of ERCOT.<br>b. 1.2 - We believe that 1000 MVAR may too large, and should be reduced to 500 MVAR. However criterion 1.2 could just be deleted, since any significant reactive resources would be picked up under criterion 1.8<br>c. 1.3 - “Generation designated as required for reliability purposes” doesn’t seem to be a very “bright-line”. We believe this criterion should be further clarified by including language from the “Rationale and Implementation Reference Document”.<br>d. 1.4 - Need to clarify that this criterion only includes the primary Blackstart Resources. Entities may include various alternative resources in their restoration plans which aren’t Critical Assets, but which may not be clearly distinguished from the primary Blackstart Resources in the restoration plan. Add the phrase “that the entity intends to rely on for system restoration”.<br>e. 1.5 - The CIPDT is looking to the industry to define Critical Assets based on NERC definitions that are somewhat ambiguous and can be redefined by Standard Drafting Teams any time a group of standards is proposed. This could lead to Critical Assets being removed or added without proper analysis being performed on the impact to the system. Also, the definition of Cranking Path could be debated that it could be from a generating source that provides electricity to a larger resource during restoration. This source could be a small diesel that is sitting next to a large generator that provides the electricity to lift pumps, exciter field, or some other device that provides the means for a larger generator to become a Blackstart Resource. Or it could be argued that the cranking path is from a Blackstart Resource to fossil plants on the system that are used to facilitate the restoration of the system. Duke Energy requests that the Drafting team rewrite this requirement so that it does not use this term. Duke Energy also believes that the CIPDT should get input from those that are familiar with Restoration by requesting input from the Emergency Operations Drafting Team. We propose rewriting 1.5 as follows: The Facilities comprising the current carrying path from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator’s restoration plan, up to the point where multiple path options exist.<br>f. 1.8 & 1.9 - These two criteria need clarification. First, it should be made clear that this IROL evaluation is to be made in the planning timeframe, because the purpose is to identify Critical Cyber Assets that need to be protected, which is an activity that takes place in the planning timeframe. Also, including the word “destroyed” in the phrase “destroyed, degraded, |

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| | | | | misused or otherwise rendered unavailable" creates significant uncertainty regarding what the IROL analysis is intended to encompass. Add the phrase "via cyber attack" after the word "unavailable". This will clarify that the evaluation only encompasses destruction, degradation or misuse that can be achieved via cyber attack, and not a physical attack on the station. For example, physical attack could imply multiple transmission lines shorted to ground, which entails a much different analysis than transmission lines removed from service via cyber attack. NOTE: The physical security provided by the CIP standards is focused on protection of the Critical Cyber Assets, not the Critical Assets.<br>g. 1.10 - As with our comment on 1.8 & 1.9 above, add the phrase "via cyber attack" after the word "unavailable". We also have a concern that if an entity fails to identify a facility under 1.1 or 1.3, they will also be in violation for failing to identify the corresponding Transmission Facilities under 1.10 (i.e. the double jeopardy issue). Need to replace the phrase "described in" with the phrase "identified by an entity pursuant to". Alternatively, 1.10 could be folded into 1.1 and 1.3 by adding the phrase "and Transmission Facilities providing the generation interconnection" to those criteria.<br>h. 1.11 - Need to clarify that these Transmission Facilities are those that are specifically identified in the Nuclear Plant Interface Requirements (NPIRs) in the Agreement developed between the Nuclear Plant Generator Operator and applicable Transmission Entities pursuant to NUC-001-2. At the end of this criterion add the phrase "in the Agreement(s) required by NUC-001 R2."<br>i. 1.12 - As with our comment on 1.8 & 1.9 above, this criterion should be revised to clarify that this IROL evaluation is to be made in the planning timeframe, because the purpose is to identify Critical Cyber Assets that need to be protected, which is an activity that takes place in the planning timeframe. Also, the phrase "destroyed, degraded, misused or otherwise rendered unavailable" needs to be clarified by adding the phrase "via cyber attack" after the word "unavailable".<br>j. 1.13 - Load control programs shouldn't be defined as Critical Assets but rather Critical Cyber Assets, since they are a function of the control center, which is already a Critical Asset. Replace the word "Common" with the phrase "Each control center or backup control center used to". Also, clarify the meaning of "automatic" by inserting the parenthetical (without human intervention) after the word "automatic".<br>k. 1.14 - This criterion is far too broad because we don't have an approved |

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| | | | | NERC definition of control room, control system, backup control room or backup control system. Many switchyards and substations have control systems that could be used to perform transmission functions, but that doesn't mean that they are "Critical Assets". Remove control system and backup control system from this criterion and limit it to identifying the control centers and backup control centers associated with the Critical Assets on the transmission system, just as criteria 1.15 links identification of the control center or backup co |

**Response**: Thank you for your comments.

The SDT agrees that other changes ultimately need to be made to the body of CIP standards, and expects to post them next year.

Item 1.1 - Prior drafts had wording about reserve sharing for the threshold. The SDT received feedback that that wording was confusing, that the amount referred to in the reserve sharing was not a specific amount, and that the amounts changed daily. The drafting team conducted an informal survey of the regions, and identified what the megawatt value of the reserve sharing would be for various groups. The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BAs in all regions. Based on information provided on the DOE website, the SDT believes that an increased amount of generation capacity will be classified as Critical Assets in the US.

Item 1.2 – The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.

Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."

Item 1.4 – A Blackstart Resource is defined as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." EOP-005-2 R1.4 states that the restoration plan must include "Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit." The SDT feels that these Blackstart Resources must be classified as Critical Assets. It should be noted that not all blackstart generators must be designated as Blackstart Resources.

Item 1.5 – NERC standard EOP-005-2 R1.5, "Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started," designates that Cranking Paths must be identified.

Items 1.8 & 1.9 – Cyber analysis is contained in Requirement R2, not in the identification of Critical Assets.

Item 1.10 – Cyber analysis is contained in Requirement R2, not in the identification of Critical Assets. There is no double jeopardy, since all

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| of these criteria are contained in the same Requirement.<br><br>Item 1.11 – The SDT does not believe that adding the phrase "in the Agreement(s) required by NUC-001 R2" provides any clarification, since the defined NERC term Nuclear Plant Interface Requirements is "The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities."<br><br>Item 1.12 – Cyber analysis is contained in Requirement R2, not in the identification of Critical Assets.<br><br>Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection." | | | | |
| Kevin Querry | FirstEnergy Solutions | 3 | Affirmative | FirstEnergy appreciates the CIP Standard Drafting Team's (SDT) careful consideration of our and other stakeholder feedback during prior comment periods and the SDT's decision to develop the CIP-002-4 bright-line standard. The development of CIP-002-4 and continued use of the CIP-003 through CIP-009 standards brings needed industry consistency in Critical Asset determinations while appropriately building upon prior industry efforts of implementing the CIP standards. FirstEnergy supports CIP-002-4 and is voting AFFIRMATIVE for the standard but believes changes are needed to better clarify Attachment 1. In our view, some of the criteria are vaguely written and subject to interpretation - specifically criteria 1.8 and 1.11 - and we offer suggestions for improving expectations and compliance certainty. Additionally, we suggest less substantive changes to criteria 1.5 and 1.14 for clarity and consistency. Lastly, we encourage the SDT to reconsider its Implementation Plan for the CIP version 4 standards. The Implementation Plan is a 15 page document which is overly complex and difficult to understand.<br>Please refer to FE's comments submitted through the parallel comment period for suggestions for improvement and simplification. The following are FirstEnergy's proposed Attachment 1 changes:<br>1) Criterion 1.8 currently states "Transmission Facilities at a single station |

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| | | | | location that, if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs).” Clarity needed: A.) It is not evident who is responsible for identifying the applicable transmission facilities covered by 1.8. B.) Item 1.8 should rely on review/analysis that is regularly performed by industry in meeting other NERC reliability standards. Item 1.8 should be based on IROL determinations made from planning horizon studies and information communicated to responsible entities via FAC-010/FAC-014. C.) A possible misinterpretation of Attachment 1, Item 1.8 is that it is intended to review a complete loss of substation. However the words say “Transmission Facilities at a single station location …” not all transmission facilities at a single substation location. Based on the above items, FirstEnergy proposes the following for item 1.8: “1.8. Transmission Facilities designated by the Planning Coordinator or Transmission Planner that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL).” The Planning Coordinator and Transmission Planner determine and communicate IROLs in the planning time horizon per NERC reliability standard FAC-014. The subject Transmission Facilities are the contingency Transmission Facilities communicated by the PC and TP per requirement R5 of FAC-014. The 1.8 criterion should not appear to require any new study or analysis by the TP or PC.<br>2) Criterion 1.11 currently states “Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements” Clarity needed: The term “essential” is vague and open to interpretation. FE suggests that the SDT focus on Transmission Facilities identified in Nuclear Plant Interface Requirements identified as providing offsite power supply for nuclear plant safety requirements. We propose the following change for 1.11: “1.11 Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements.” 3) Criterion 1.5 currently states “The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist.” FirstEnergy suggests replacing the word “multiple” with “two or more” for clarity. 4) Criterion 1.14 currently states “Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator.” FirstEnergy suggests removing the |

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<tr><td colspan="5">Response: Thank you for your comments.<br><br>Item 1.8 – This criterion has been changed to “Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.”<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2 “Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.” It is not limited to offsite power requirements.<br><br>Item 1.5 – This criterion has been reworded to “The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist as identified in the Transmission Operator's restoration plan.”<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”<br><br>The SDT has simplified the Implementation Plan to reference the Effective Date of CIP-002-4 through CIP-009-4 which is 8 calendar quarters after regulatory approval.</td></tr>
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| Charles Locke | Kansas City Power & Light Co. | 3 | Affirmative | The bright lines established by the proposed standard have not been established with a strong engineering basis and do not necessarily reflect a true measure of reliability impact to the bulk electric system. It is recommended to develop a process to determine a true reliability assessment and adjust the bright line proposed here to a deliberate and supportable definition. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| David Burke | Orange and Rockland Utilities, Inc. | 3 | Affirmative | 1. New Requirement R1: ORU requests an explicit definition of "annual." In addition, it is not clear whether the "update as necessary" applies to updates to the list during the annual review. The language should be clarified to more definitely express the "update as necessary" to be applicable to the list during the annual review.<br>2. New Requirement R2: In addition, there is no reason for the parenthetical with the specific inclusion of nuclear generation. It should be removed.<br>3. Attachment 1/Requirement R2: ORU suggests the removal of "control system" and "backup control system" in Attachment 1, Part 1.14. These systems should be identified as part of new Requirement R2, Critical Cyber Asset Identification.<br>4. Attachment 1: Part 1.3 is extremely broad and is under defined. Either delete it or provide additional specificity delineating the limited range of circumstances when a PC or TP may designate a facility as critical.<br>5. Attachment 1: Part 1.10 uses the phrase "the loss of the assets" without describing the relevant time period. Are these assets losses for a few cycles, for a few minutes, for a few hours or for a few days? We recommend that the conclusion of Part 1.10 state "...would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3 for a period of xx hours (e.g., 24 hours) or more."<br>6. Implementation Plan: Agreed, so long as an Entity can have access to an exception process with an implementation plan to request additional time due to a large increase in identified assets, without a self-reported violation, within an implementation schedule. |
| **Response**: Thank you for your comments.<br><br>1) The phraseology you are concerned about exists in the existing CIP-002-3 standard. The SDT expects to correct this phraseology in the next version. | | | | |

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| 2) The parenthetical statement about nuclear generation comes from Attachment 1 criterion 1.1.<br>3) Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."<br>4) Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."<br>5) The phrase "loss of assets" is not limited to any period of time. A trip and a 24-hour outage would both apply.<br>6) Thank you for your comments. | | | | |
| Dana Wheelock | Seattle City Light | 3 | Affirmative | Specifically, Seattle City Light commends the change to a "bright line" approach to identifying Critical Assets as proposed in draft CIP-002-4. The use of nationwide criteria reasonably captures as Critical Assets the large generating units and high voltage transmission facilities essential to the reliable operation of the North American Bulk Power System. The flexibility afforded individual Planning Coordinators and Transmission Planners to specify additional facilities as Critical Assets important to local reliability furthers the objective of Bulk Power System reliability by allowing some smaller generating units and transmission facilities to be called out as Critical Assets without drawing in all assets of a certain size that are not critical elsewhere. These changes are consistent with Seattle City Light's philosophy towards Critical Assets, which always has been about stepping up and acknowledging the importance of identifying and protecting all Critical Assets essential to the reliability of the bulk power system. Ultimately CIP-002-4 as proposed promises to benefit the electricity industry, consumers, and North America by improving reliability through a certain and consistent application of the Critical Asset identification process. That said, Seattle City Light expresses concern that imperfections in the language of draft CIP-002-4 may frustrate its promise of bringing Critical Asset certainty and consistency. Imprecise language has been a recurring problem all throughout the short life of the NERC Mandatory Reliability Standards. Unnecessary compliance difficulties, tortured interpretations, and wasteful efforts have resulted. Lack of care with language threatens the existing regulatory regime by fostering distrust |

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| | | | | among industry, regulators, government, and the public at large. As such the comments below are offered as potential corrections to the details of draft and not as reflecting on the “bright-line” approach of proposed CIP-002-4.<br>1. Requirement 2 of draft CIP-002-4 states, “For each group of generating units (including Nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes.” Seattle City Light follows Tacoma Power in finding the term ‘shared Cyber Assets’ unclear and suggests clarification as follows: “For each group of generating units (including Nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those Cyber Assets networked to a system that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes.”<br>2. Critical Asset criterion 1.7 of CIP-002-4, Appendix A, identifies as Critical Assets “Transmission facilities operated at 300 kV or higher at stations interconnected at 300 kV of higher with three or more other transmission stations.” Seattle City Light agrees with Lower Colorado River Authority that additional detail is needed about the nature of the specified interconnections. In particular, questions exist as to type (what about a radial line connected to a generator-does it count?) and distance (does a high-voltage bus count if connected to another substation a dozen feet away?).<br>3. Critical Asset criterion 1.13 indicates that “Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes” are Critical Assets. Seattle City Light concurs with the assessment of APPA and others that this wording may inadvertently include any SCADA system that controls 300 MW or more of load (and thus has ‘capability’ to shed it), and recommends wording similar to item 1.11 of draft CIP-010-1, “BES elements that perform automatic aggregate load shedding of 300 MW or more within 15 minutes.”<br>4. Critical Asset criterion 1.15 states “Each control center or backup control center used to control generation identified as a Critical Asset, or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection.” Seattle City Light concurs with APPA in understanding that this criterion is intended to apply to control centers controlling multiple |

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<tr><td colspan="5">Response: Thank you for your comments.<br><br>1) Requirement R2 has been changed to clarify the issues presented.<br>2) Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Assets Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations. There is no distance requirement in the criterion.<br>3) Item 1.13 – This criterion has been changed to “Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”<br>4) Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”</td></tr>
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<tr><td>Guy Andrews</td><td>Georgia System Operations Corporation</td><td>4</td><td>Affirmative</td><td>Additional clarity is needed to criteria 1.15 in Attachment 1 regarding what constitutes control. For example, merely sending set points to a generator which will reject those inputs if they are outside preset parameters should not constitute control of that generation.</td></tr>
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| center used to control aggregate generation equal to or exceeding 1500 MWs in a single Interconnection.” | | | | |
| Douglas Hohlbaugh | Ohio Edison Company | 4 | Affirmative | FirstEnergy appreciates the CIP Standard Drafting Team’s (SDT) careful consideration of our and other stakeholder feedback during prior comment periods and the SDT’s decision to develop the CIP-002-4 bright-line standard. The development of CIP-002-4 and continued use of the CIP-003 through CIP-009 standards brings needed industry consistency in Critical Asset determinations while appropriately building upon prior industry efforts of implementing the CIP standards. FirstEnergy supports CIP-002-4 and is voting AFFIRMATIVE for the standard but believes changes are needed to better clarify Attachment 1. In our view, some of the criteria are vaguely written and subject to interpretation - specifically criteria 1.8 and 1.11 - and we offer suggestions for improving expectations and compliance certainty. Additionally, we suggest less substantive changes to criteria 1.5 and 1.14 for clarity and consistency. Lastly, we encourage the SDT to reconsider its Implementation Plan for the CIP version 4 standards. The Implementation Plan is a 15 page document which is overly complex and difficult to understand. Please refer to FE’s comments submitted through the parallel comment period for suggestions for improvement and simplification. The following are FirstEnergy’s proposed Attachment 1 changes:<br>1) Criterion 1.8 currently states “Transmission Facilities at a single station location that, if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs).” Clarity needed: A.) It is not evident who is responsible for identifying the applicable transmission facilities covered by 1.8. B.) Item 1.8 should rely on review/analysis that is regularly performed by industry in meeting other NERC reliability standards. Item 1.8 should be based on IROL determinations made from planning horizon studies and information communicated to responsible entities via FAC-010/FAC-014. C.) A possible misinterpretation of Attachment 1, Item 1.8 is that it is intended to review a complete loss of substation. However the words say “Transmission Facilities at a single station location ...” not all transmission facilities at a single substation location. Based on the above items, FirstEnergy proposes the following for item 1.8: “1.8. Transmission Facilities designated by the Planning Coordinator or Transmission Planner that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL).” The Planning |

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**Response**: Thank you for your comments.

Item 1.8 – This criterion has been changed to "Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2, "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." It is not limited to offsite power requirements.

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| Hao Li | Seattle City Light | 4 | Affirmative | Specifically, Seattle City Light commends the change to a "bright-line" approach to identifying Critical Assets as proposed in draft CIP-002-4. The use of nationwide criteria reasonably captures as Critical Assets the large generating units and high voltage transmission facilities essential to the reliable operation of the North American Bulk Power System. The flexibility afforded individual Planning Coordinators and Transmission Planners to specify additional facilities as Critical Assets important to local reliability furthers the objective of Bulk Power System reliability by allowing some smaller generating units and transmission facilities to be called out as Critical Assets without drawing in all assets of a certain size that are not critical elsewhere. These changes are consistent with Seattle City Light's philosophy towards Critical Assets, which always has been about stepping up and acknowledging the importance of identifying and protecting all Critical Assets essential to the reliability of the bulk power system. Ultimately CIP-002-4 as proposed promises to benefit the electricity industry, consumers, and North America by improving reliability through a certain and consistent application of the Critical Asset identification process. That said, Seattle City Light expresses concern that imperfections in the language of draft CIP-002-4 may frustrate its promise of bringing Critical Asset certainty and consistency. Imprecise language has been a recurring problem all throughout the short life of the NERC Mandatory Reliability Standards. Unnecessary compliance difficulties, tortured interpretations, and wasteful efforts have resulted. Lack of care with language threatens the existing regulatory regime by fostering distrust among industry, regulators, government, and the public at large. As such |

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| | | | | backup control center used to control multiple generation units identified as Critical Assets, or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection.” |
| **Response**: Thank you for your comments.<br><br>1) Requirement R2 has been changed to clarify the issues presented.<br>2) Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Asset a Transmission Facility operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations. There is no distance requirement in the criterion.<br>3) Item 1.13 – This criterion has been changed to “System(s) or facilities that perform automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.”<br>4) Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.” | | | | |
| Keith Morisette | Tacoma Public Utilities | 4 | Affirmative | Tacoma Power has submitted comments during the comment period for Version 4 of the CIP standards. If there is a subsequent future ballot for Project 2008-06, consideration of all submitted comments need to be reflected in such ballot. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Max Emrick | City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | 5 | Affirmative | Tacoma Power has submitted comments during the comment period for Version 4 of the CIP standards. If there is a subsequent future ballot for Project 2008-06, consideration of all submitted comments need to be reflected in such ballot. |

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| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Amir Y Hammad | Constellation Power Source Generation, Inc. | 5 | Affirmative | This affirmative ballot is contingent on successfully addressing specific comments submitted on the Formal Comment Form for Project 2008-06 Cyber Security 706. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Kenneth Dresner | FirstEnergy Solutions | 5 | Affirmative | FirstEnergy appreciates the CIP Standard Drafting Team's (SDT) careful consideration of our and other stakeholder feedback during prior comment periods and the SDT's decision to develop the CIP-002-4 bright-line standard. The development of CIP-002-4 and continued use of the CIP-003 through CIP-009 standards brings needed industry consistency in Critical Asset determinations while appropriately building upon prior industry efforts of implementing the CIP standards. FirstEnergy supports CIP-002-4 and is voting AFFIRMATIVE for the standard but believes changes are needed to better clarify Attachment 1. In our view, some of the criteria are vaguely written and subject to interpretation - specifically criteria 1.8 and 1.11 - and we offer suggestions for improving expectations and compliance certainty. Additionally, we suggest less substantive changes to criteria 1.5 and 1.14 for clarity and consistency. Lastly, we encourage the SDT to reconsider its Implementation Plan for the CIP version 4 standards. The Implementation Plan is a 15 page document which is overly complex and difficult to understand. Please refer to FE's comments submitted through the parallel comment period for suggestions for improvement and simplification. The following are FirstEnergy's proposed Attachment 1 changes:<br>1) Criterion 1.8 currently states "Transmission Facilities at a single station location that, if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs)." Clarity needed: A.) It is not evident who is responsible for identifying the applicable transmission facilities covered by 1.8. B.) Item 1.8 should rely on review/analysis that is regularly performed by industry in meeting other NERC reliability standards. Item 1.8 should be based on IROL determinations made from planning horizon studies and information communicated to responsible entities via FAC-010/FAC-014. C.) A possible |

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| | | | | misinterpretation of Attachment 1, Item 1.8 is that it is intended to review a complete loss of substation. However the words say "Transmission Facilities at a single station location ..." not all transmission facilities at a single substation location. Based on the above items, FirstEnergy proposes the following for item 1.8: "1.8. Transmission Facilities designated by the Planning Coordinator or Transmission Planner that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL)." The Planning Coordinator and Transmission Planner determine and communicate IROLs in the planning time horizon per NERC reliability standard FAC-014. The subject Transmission Facilities are the contingency Transmission Facilities communicated by the PC and TP per requirement R5 of FAC-014. The 1.8 criterion should not appear to require any new study or analysis by the TP or PC.<br>2) Criterion 1.11 currently states "Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements" Clarity needed: The term "essential" is vague and open to interpretation. FE suggests that the SDT focus on Transmission Facilities identified in Nuclear Plant Interface Requirements identified as providing offsite power supply for nuclear plant safety requirements. We propose the following change for 1.11: "1.11 Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements."<br>3) Criterion 1.5 currently states "The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist." FirstEnergy suggests replacing the word "multiple" with "two or more" for clarity.<br>4) Criterion 1.14 currently states "Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator." FirstEnergy suggests removing the text "control system" and "or backup control system" for consistency to criteria 1.15. If the intent is to ensure coverage of offsite data centers or telecommunication centers that support the "control center" then the SDT should provide a separate criterion in Attachment 1. To extend coverage of 1.14 and not 1.15 is inconsistent and the use of the phrase "control system" is vague. |

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>Item 1.8 – This criterion has been changed to “Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.”<br><br>Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2 “Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.”  It is not limited to offsite power requirements.<br><br>Item 1.5 – This criterion has been reworded to “The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist as identified in the Transmission Operator's restoration plan.”<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.”  A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.”  A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13.  Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”<br><br>The SDT has simplified the Implementation Plan to reference the Effective Date of CIP-002-4 through CIP-009-4 which is 8 calendar quarters after regulatory approval.</td></tr>
<tr><td>Michelle DAntuono</td><td>Occidental Chemical</td><td>5</td><td>Affirmative</td><td>Although Occidental Chemical has voted to approve CIP-002-4, we are concerned about the ambiguous wording under Criterion 1.3 “Each generation Facility that the Planning Coordinator or Transmission Planner designates as required for reliability purposes.” Although clarified in the CIP-002-4 Rationale and Implementation Reference Document as those generation facilities designated as “Reliability Must Run”, the language in the standard is the ultimate arbiter. We understand that not all regions use the term “Reliability Must Run”, but Criterion 1.3 as written is too open-ended - which violates the intent of NERC’s goal to develop requirements that are clear and measurable.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>Item 1.3 –This criterion has been reworded to “Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.”</td></tr>
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| Annette M Bannon | PPL Generation LLC | 5 | Affirmative | Regarding Attachment 1, section 1.1, a generation plant that is tripped as part of a Remedial Action Scheme (Special Protection System) to protect the Bulk Electric System should be exempted from Critical Asset designation. The inclusion of a generation plant in a RAS scheme infers that the plant is not critical to the operation of the BES. NERC included this same criteria in their guidance document "Security Guideline for the Electricity Sector: Identifying Critical Assets," page 10, table C-2. |
| **Response**: Thank you for your comments.<br><br>The Remedial Action Scheme would be covered under criterion 1.12. The plant would not be exempted if it met any of the criteria in Attachment 1. | | | | |
| Michael J. Haynes | Seattle City Light | 5 | Affirmative | Specifically, Seattle City Light commends the change to a "bright-line" approach to identifying Critical Assets as proposed in draft CIP-002-4. The use of nationwide criteria reasonably captures as Critical Assets the large generating units and high voltage transmission facilities essential to the reliable operation of the North American Bulk Power System. The flexibility afforded individual Planning Coordinators and Transmission Planners to specify additional facilities as Critical Assets important to local reliability furthers the objective of Bulk Power System reliability by allowing some smaller generating units and transmission facilities to be called out as Critical Assets without drawing in all assets of a certain size that are not critical elsewhere. These changes are consistent with Seattle City Light's philosophy towards Critical Assets, which always has been about stepping up and acknowledging the importance of identifying and protecting all Critical Assets essential to the reliability of the bulk power system. Ultimately CIP-002-4 as proposed promises to benefit the electricity industry, consumers, and North America by improving reliability through a certain and consistent application of the Critical Asset identification process. That said, Seattle City Light SME expresses concern that imperfections in the language of draft CIP-002-4 may frustrate its promise of bringing Critical Asset certainty and consistency. Imprecise language has been a recurring problem all throughout the short life of the NERC Mandatory Reliability Standards. Unnecessary compliance difficulties, tortured interpretations, and wasteful efforts have resulted. Lack of care with language threatens the existing regulatory regime by fostering distrust among industry, regulators, government, and the public at large. As such the comments below are offered as potential corrections to the details of draft and not as reflecting on the "bright-line" approach of proposed CIP-002-4. |

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| | | | | 1. Requirement 2 of draft CIP-002-4 states, "For each group of generating units (including Nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes." Seattle City Light follows Tacoma Power in finding the term 'shared Cyber Assets' unclear and suggests clarification as follows: "For each group of generating units (including Nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those Cyber Assets networked to a system that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes."<br>2. Critical Asset criterion 1.7 of CIP-002-4, Appendix A, identifies as Critical Assets "Transmission facilities operated at 300 kV or higher at stations interconnected at 300 kV of higher with three or more other transmission stations." Seattle City Light agrees with Lower Colorado River Authority that additional detail is needed about the nature of the specified interconnections. In particular, questions exist as to type (what about a radial line connected to a generator-does it count?) and distance (does a high-voltage bus count if connected to another substation a dozen feet away?).<br>3. Critical Asset criterion 1.13 indicates that "Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes" are Critical Assets. Seattle City Light concurs with the assessment of APPA and others that this wording may inadvertently include any SCADA system that controls 300 MW or more of load (and thus has 'capability' to shed it), and recommends wording similar to item 1.11 of draft CIP-010-1, "BES elements that perform automatic aggregate load shedding of 300 MW or more within 15 minutes."<br>4. Critical Asset criterion 1.15 states "Each control center or backup control center used to control generation identified as a Critical Asset, or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection." Seattle City Light concurs with APPA in understanding that this criterion is intended to apply to control centers controlling multiple units, and recommends the following wording: "Each control center or backup control center used to control multiple generation units identified as Critical Assets, or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection." |

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| **Response**: Thank you for your comments.<br><br>1) Requirement R2 has been changed to clarify the issues presented.<br>2) Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Asset a Transmission Facility operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations. There is no distance requirement in the criterion.<br>3) Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."<br>4) Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection." | | | | |
| Scott M. Helyer | Tenaska, Inc. | 5 | Affirmative | Regarding the Critical Asset Criteria, it seems that the 300 MW referred to in 1.13 should be 1500 MW to make it consistent with generation. |
| **Response**: Thank you for your comment.<br><br>Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program." | | | | |
| Martin Bauer P.E. | U.S. Bureau of Reclamation | 5 | Affirmative | The vote reflects that project can generally move forward we offer the following comments to improve the criterion in CIP-002-4 Attachment 1. Criterion 1.1 uses the phrase "aggregate highest rated net Real Power capability. The Rationale and Implementation Reference Document states the term "net Real Power capability" is drawn from MOD-024. However, use of that standard is questionable on at least two counts, the first being that it has yet to be approved by FERC, and that it is a "fill-in-the-black" standard that FERC has stated it finds unacceptable. As MOD-024 would rely on the Reliability Assurer's procedures, it could not assure a uniform application across the Interconnections. We suggest instead "Each group of generating units (including nuclear generation) at a single plant location with an aggregate highest Facility Rating, pursuant to FAC-008/009, equal |

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| | | | | to or exceeding 1500 MW.” Criterion 1.8 refers to conditions which would “violate one or more Interconnection Reliability Operating Limits (IROLs)” for transmission Facilities at a single station. However, Transmission Owners are not on the list of Responsible Entities with whom coordination of identified SOL’s or IROL’s is required in the Reliability Standards. This would make it difficult for a Transmission Owner to assess the facility based on the criterion. Criterion 1.12 has similar requirements as Criterion 1.8, but applies to Special Protection Systems, Remedial Action Schemes or automated switching systems. Where a Responsible Entity either provides information to one of these systems/schemes or responds to such a scheme, without being the “owner/operator” of the scheme may not be privy to knowing if an IROL is or could be violated. This would make it difficult for the Responsible Entity to assess the facility based on the criterion. We suggest that a requirement that Responsible Entities, who have the Reliability Standards obligations to identify System Operating Limits (SOL’s) and IROL’s, must respond if requested by a Responsible Entity whom they are not currently required notify. This would permit the Responsible Entity to assess his facility or systems/schemes. |
| **Response**: Thank you for your comments.<br><br>Item 1.1 – The SDT chose to use “net Real Power capability” instead of Facility Rating due to the fact that it is a more accurate reflection on generation output to the system.<br><br>Items 1.8 and 1.12 – FAC-014-2 R5 states “The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:” | | | | |
| Nickesha P Carrol | Consolidated Edison Co. of New York | 6 | Affirmative | 1. New Requirement R1: We request an explicit definition of “annual.” In addition, it is not clear whether the “update as necessary” applies to updates to the list during the annual review. The language should be clarified to more definitely express the “update as necessary” to be applicable to the list during the annual review.<br>2. New Requirement R2: In addition, there is no reason for the parenthetical with the specific inclusion of nuclear generation. It should be removed.<br>3. Attachment 1/Requirement R2: We suggest the removal of “control system” and “backup control system” in Attachment 1, Part 1.14. These systems should be identified as part of new Requirement R2, Critical Cyber Asset Identification. |

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<tr><td></td><td></td><td></td><td></td><td>4. Attachment 1: Part 1.3 is extremely broad and is under defined. Either delete it or provide additional specificity delineating the limited range of circumstances when a PC or TP may designate a facility as critical.<br>5. Attachment 1: Part 1.10 uses the phrase “the loss of the assets” without describing the relevant time period. Are these assets losses for a few cycles, for a few minutes, for a few hours or for a few days? We recommend that the conclusion of Part 1.10 state “...would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3 for a period of xx hours (e.g., 24 hours) or more.”<br>6. Implementation Plan: Agreed, so long as an Entity can have access to an exception process with an implementation plan to request additional time due to a large increase in identified assets, without a self-reported violation, within an implementation schedule.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>1) The phraseology you are concerned about exists in the existing CIP-002-3 standard. The SDT expects to correct this phraseology in the next version.<br>2) The parenthetical statement about nuclear generation comes from Attachment 1 criterion 1.1.<br>3) Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”<br>4) Item 1.3 – This criterion has been reworded to “Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.”<br>5) The phrase “loss of assets” is not limited to any period of time. A trip and a 24-hour outage would both apply.<br>6) Thank you for your comments.</td></tr>
<tr><td>Mark S Travaglianti</td><td>FirstEnergy Solutions</td><td>6</td><td>Affirmative</td><td>FirstEnergy appreciates the CIP Standard Drafting Team’s (SDT) careful consideration of our and other stakeholder feedback during prior comment periods and the SDT’s decision to develop the CIP-002-4 bright-line standard. The development of CIP-002-4 and continued use of the CIP-003 through CIP-009 standards brings needed industry consistency in Critical Asset determinations while appropriately building upon prior industry efforts of implementing the CIP standards. FirstEnergy supports CIP-002-4</td></tr>
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| | | | | and is voting AFFIRMATIVE for the standard but believes changes are needed to better clarify Attachment 1. In our view, some of the criteria are vaguely written and subject to interpretation - specifically criteria 1.8 and 1.11 - and we offer suggestions for improving expectations and compliance certainty. Additionally, we suggest less substantive changes to criteria 1.5 and 1.14 for clarity and consistency. Lastly, we encourage the SDT to reconsider its Implementation Plan for the CIP version 4 standards. The Implementation Plan is a 15 page document which is overly complex and difficult to understand. Please refer to FE's comments submitted through the parallel comment period for suggestions for improvement and simplification. The following are FirstEnergy's proposed Attachment 1 changes: 1) Criterion 1.8 currently states "Transmission Facilities at a single station location that, if destroyed, degraded, misused or otherwise rendered unavailable, violate one or more Interconnection Reliability Operating Limits (IROLs)." Clarity needed: A.) It is not evident who is responsible for identifying the applicable transmission facilities covered by 1.8. B.) Item 1.8 should rely on review/analysis that is regularly performed by industry in meeting other NERC reliability standards. Item 1.8 should be based on IROL determinations made from planning horizon studies and information communicated to responsible entities via FAC-010/FAC-014. C.) A possible misinterpretation of Attachment 1, Item 1.8 is that it is intended to review a complete loss of substation. However the words say "Transmission Facilities at a single station location ..." not all transmission facilities at a single substation location. Based on the above items, FirstEnergy proposes the following for item 1.8: "1.8. Transmission Facilities designated by the Planning Coordinator or Transmission Planner that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL)." The Planning Coordinator and Transmission Planner determine and communicate IROLs in the planning time horizon per NERC reliability standard FAC-014. The subject Transmission Facilities are the contingency Transmission Facilities communicated by the PC and TP per requirement R5 of FAC-014. The 1.8 criterion should not appear to require any new study or analysis by the TP or PC. 2) Criterion 1.11 currently states "Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements" Clarity needed: The term "essential" is vague and open to interpretation. FE suggests that the SDT focus on Transmission Facilities identified in Nuclear Plant Interface Requirements identified as providing offsite power supply for nuclear plant safety requirements. We propose the |

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| | | | | following change for 1.11: “1.11 Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements.” 3) Criterion 1.5 currently states “The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where multiple path options exist.” FirstEnergy suggests replacing the word “multiple” with “two or more” for clarity. 4) Criterion 1.14 currently states “Each control center, control system, backup control center, or backup control system used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator.” FirstEnergy suggests removing the text “control system” and “or backup control system” for consistency to criteria 1.15. If the intent is to ensure coverage of offsite data centers or telecommunication centers that support the “control center” then the SDT should provide a separate criterion in Attachment 1. To extend coverage of 1.14 and not 1.15 is inconsistent and the use of the phrase “control system” is vague. |

**Response**: Thank you for your comments.

Item 1.8 – This criterion has been changed to “Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.”

Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2 “Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.” It is not limited to offsite power requirements.

Item 1.5 – This criterion has been reworded to “The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist as identified in the Transmission Operator's restoration plan.”

Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to “Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.” A new criterion, 1.16, has been added which states, “Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.” A new criterion, 1.17, has also been added which states, ”Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection.”

The SDT has simplified the Implementation Plan to reference the Effective Date of CIP-002-4 through CIP-009-4 which is 8 calendar quarters

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| after regulatory approval. | | | | |
| Silvia P Mitchell | Florida Power & Light Co. | 6 | Affirmative | The standard CIP-002-4 includes a more consistent method for the evaluation of Critical Assets and removes the variability that is introduced when letting Entity's perform their own risk-based methodology. It is requested to include an exception process in the implementation plan for a company that has a large number of new CA(s). For consistency, make all of the cases fall under the 24 month timeline to remove the possible misinterpretation of the Categories as stated in proposed revisions to the implementation plan for newly identified CCAs and Responsible Entities. The only exception to the 24-month requirement shall be those newly identified CCAs and Responsible Entities that require compliance before commissioning. Depending on the number of CCAs a utility needs to protect, the resources needed to accomplish the lockdowns may not be available. We recommend a 24-month implementation time frame for all categories. This would make the criteria for compliance more consistent. Industry will be competing for cyber security resources for implementation. We are also very concerned that the expectation is to replace CCA's with TFEs with assets not requiring an exception. In general, this is the correct direction to go in, but in practice this is not necessarily easy. For example, If tomorrow an asset with a TFE fails in service and needs to be replaced with a similar asset, it instead must be replaced with a "technically compliant" asset. This may be impractical early on as stocking levels may be inadequate and qualified replacements may not have been fully vetted for the application. |
| **Response**: Thank you for your comments.<br><br>Thank you for your comments. The SDT has simplified the Implementation Plan to reference the Effective Date of CIP-002-4 through CIP-009-4 which is 8 calendar quarters after regulatory approval | | | | |
| Jessica L Klinghoffer | Kansas City Power & Light Co. | 6 | Affirmative | The bright-lines established by the proposed standard have not been established with a strong engineering basis and do not necessarily reflect a true measure of reliability impact to the bulk electric system. It is recommended to develop a process to determine a true reliability assessment and adjust the bright-line proposed here to a deliberate and supportable definition. |

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| **Response:** Thank you for your comment. The SDT believes that the implementation of Attachment 1 criteria will increase the consistency of Critical Asset identification over the existing entity defined risk-based methodology. | | | | |
| Dennis Sismaet | Seattle City Light | 6 | Affirmative | Seattle City Light Subject Matter Expert (SME) supports the changes proposed for CIP-002-4 and recommends a “yes” vote despite imperfections with the language of draft Appendix A. SME recommends comments in the hope that the language yet will be clarified. Specifically, Seattle City Light commends the change to a “bright-line” approach to identifying Critical Assets as proposed in draft CIP-002-4. The use of nationwide criteria reasonably captures as Critical Assets the large generating units and high voltage transmission facilities essential to the reliable operation of the North American Bulk Power System. The flexibility afforded individual Planning Coordinators and Transmission Planners to specify additional facilities as Critical Assets important to local reliability furthers the objective of Bulk Power System reliability by allowing some smaller generating units and transmission facilities to be called out as Critical Assets without drawing in all assets of a certain size that are not critical elsewhere. These changes are consistent with Seattle City Light’s philosophy towards Critical Assets, which always has been about stepping up and acknowledging the importance of identifying and protecting all Critical Assets essential to the reliability of the bulk power system. Ultimately CIP-002-4 as proposed promises to benefit the electricity industry, consumers, and North America by improving reliability through a certain and consistent application of the Critical Asset identification process. That said, Seattle City Light SME expresses concern that imperfections in the language of draft CIP-002-4 may frustrate its promise of bringing Critical Asset certainty and consistency. Imprecise language has been a recurring problem all throughout the short life of the NERC Mandatory Reliability Standards. Unnecessary compliance difficulties, tortured interpretations, and wasteful efforts have resulted. Lack of care with language threatens the existing regulatory regime by fostering distrust among industry, regulators, government, and the public at large. As such the comments below are offered as potential corrections to the details of draft and not as reflecting on the “bright-line” approach of proposed CIP-002-4.<br>1. Requirement 2 of draft CIP-002-4 states, “For each group of generating units (including Nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable |

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| | | | | operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes." Seattle City Light follows Tacoma Power in finding the term 'shared Cyber Assets' unclear and suggests clarification as follows: "For each group of generating units (including Nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those Cyber Assets networked to a system that could adversely impact the reliable operation of any combination of units that in aggregate exceed Attachment 1, criterion 1.1 within 15 minutes."<br>2. Critical Asset criterion 1.7 of CIP-002-4, Appendix A, identifies as Critical Assets "Transmission facilities operated at 300 kV or higher at stations interconnected at 300 kV of higher with three or more other transmission stations." Seattle City Light agrees with Lower Colorado River Authority that additional detail is needed about the nature of the specified interconnections. In particular, questions exist as to type (what about a radial line connected to a generator-does it count?) and distance (does a high-voltage bus count if connected to another substation a dozen feet away?).<br>3. Critical Asset criterion 1.13 indicates that "Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes" are Critical Assets. Seattle City Light concurs with the assessment of APPA and others that this wording may inadvertently include any SCADA system that controls 300 MW or more of load (and thus has 'capability' to shed it), and recommends wording similar to item 1.11 of draft CIP-010-1, "BES elements that perform automatic aggregate load shedding of 300 MW or more within 15 minutes."<br>4. Critical Asset criterion 1.15 states "Each control center or backup control center used to control generation identified as a Critical Asset, or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection." Seattle City Light concurs with APPA in understanding that this criterion is intended to apply to control centers controlling multiple units, and recommends the following wording: "Each control center or backup control center used to control multiple generation units identified as Critical Assets, or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection." |

**Response**: Thank you for your comments.

1) Requirement R2 has been changed to clarify the issues presented.
2) Item 1.7 – The intent of Criterion 1.7 is to classify as a Critical Asset a Transmission Facility operated at 300 kV or higher at stations

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| interconnected at 300 kV or higher with three or more other transmission stations. That includes upstream, downstream, networked, and radial. It should be noted that connections to generators or generation only substations are not counted in this Criterion. The source to the radial substation may be considered a Critical Asset, but the radial substation would not be considered a Critical Asset since by definition it cannot be connected to three or more transmission substations. There is no distance requirement in the criterion.<br>3) Item 1.13 – This criterion has been changed to "Each system or facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."<br>4) Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection." | | | | |
| Michael C Hill | Tacoma Public Utilities | 6 | Affirmative | Tacoma Power has submitted comments during the comment period for Version 4 of the CIP standards. If there is a subsequent future ballot for Project 2008-06, consideration of all submitted comments need to be reflected in such ballot. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Brian Evans-Mongeon | Utility Services, Inc. | 8 | Affirmative | Utility Services endorses the comments as submitted by the NPCC Regional Standards Committee, as well as the American Public Power Association (APPA). We thank the SDT for their continued efforts to address this difficult matter and urge them to consider the comments from both of these organizations as a means to strengthen the standard and its requirements. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Guy V. Zito | Northeast Power Coordinating Council, Inc. | 10 | Affirmative | Removal of the Canadian Nuclear exclusion is problematic for many of NPCC's Canadian members. Although the drafting team believed that in all cases the Canadian Nuclear Safety Commission would have authority, the onice to demonstrate and prove that the standard wouldn't apply to Canadian nukes is a burden in the view of some. |

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| **Response**: Thank you for your comments. The SDT is aware that the removal of the nuclear plant exclusion in response to a FERC order brought Canadian nuclear plants into the CIP standards. That was unintentional and will be corrected in the revised standards next posted for ballot. | | | | |
| David Batz | Edison Electric Institute | 1 | Abstain | EEI believes that the adoption of a uniform and consistent methodology for the selection of Critical Assets will enhance the reliability of the bulk power system. EEI offers the following suggested revisions for Attachment 1:<br>.............<br>1.1. Each group of generating units (including nuclear generation) at a single plant location with an aggregate highest rated net Real Power capability of the preceding 12 months equal to or exceeding 1500 MW.<br>1.2. Each reactive resource or group of resources at a single location (excluding generation Facilities) having aggregate net Reactive Power nameplate rating of 1000 MVARs or greater.<br>1.3. Each generation Facility that the Planning Coordinator or Transmission Planner has designated as required to avoid one or more reliability criteria violations.<br>1.4. Each Blackstart Resource identified in the Transmission Operator's restoration plan.<br>1.5. The Facilities comprising the Cranking Paths and initial switching requirements from the Blackstart Resource to the unit(s) to be started, as identified in the Transmission Operator's restoration plan up to the point on the Cranking Path where two or more path options exist.<br>1.6. Transmission Facilities operated at 500 kV or higher.<br>1.7. Transmission Facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations.<br>1.8. Transmission Facilities at a single station location that the Planning Coordinator or Transmission Planner has designated that, if destroyed, degraded, misused or otherwise rendered unavailable, would result in one or more Interconnection Reliability Operating Limit (IROL) violations.<br>1.9. Flexible AC Transmission Systems (FACTS) at a single station location, that, if destroyed, degraded, misused or otherwise rendered unavailable, would result in one or more Interconnection Reliability Operating Limit (IROLs) violations.<br>1.10. Transmission Facilities providing the generation interconnection required to directly connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets described in Attachment 1, criterion 1.1 or 1.3. |

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| | | | | 1.11. Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements.<br>1.12. Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limit (IROLs) violations for failure to operate as designed.<br>1.13.Common control system(s) capable of performing automatic load shedding of 300 MW or more within 15 minutes.<br>1.14. Each control center, , or backup control center, used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator.<br>1.15. Each control center or backup control center used to control generation identified as a Critical Asset, or used to control generation greater than an aggregate of 1500 MWs in a single Interconnection.<br>1.16. Any additional assets owned by the Responsible Entity that the Responsible Entity deems appropriate to include. |

**Response**: Thank you for your comments.

Item 1.1 – The guidance document posted by the SDT provides direction on the location issue. "Single plant location" refers to a group of generating units occupying a defined physical footprint and designated as an individual "plant" using commonly accepted generating facility terminology. Adjacent plants would be defined using the same criteria. The units do not necessarily have to be connected to the BES at the same substation or interconnection point in order to be considered a single plant.

Item 1.3 –This criterion has been reworded to "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon."

Item 1.5 – This criterion has been reworded to "The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist as identified in the Transmission Operator's restoration plan."

Item 1.8 – This criterion has been changed to "Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

Item 1.9 – This criterion has been changed to "Flexible AC Transmission Systems (FACTS), at a single station or substation location, that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

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| Item 1.11 – Criterion 1.11 is based on NUC-001-2 R9.2.2, "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." It is not limited to offsite power requirements.<br><br>Item 1.12 – This criterion has been changed to "Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limit (IROL) violations for failure to operate as designed."<br><br>Item 1.14 – Based on industry comments received, criterion 1.14 has been reworded to "Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator." A new criterion, 1.16, has been added which states, "Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12." A new criterion, 1.17, has also been added which states, "Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MWs in a single Interconnection."<br><br>Item 1.16 – In order to eliminate any confusion, the SDT has chosen to eliminate this criterion in the next ballot. | | | | |
| Gary Ofner | North Carolina Electric Membership Corp. | 1 | Abstain | Although NCEMC supports replacing a subjective "Risk Based Methodology" with a "Bright-line Criteria" to identify critical assets, we believe many of the proposed criteria have not been technically justified on the basis that the proposed criteria properly identify those assets which could have a material impact on the reliability of the BES. If the proposed criteria are not modified to better reflect the impact of the assets on the reliability of the BES, then there should be a provision in the standard that provides a process for an entity to technically demonstrate that even though the criteria identifies some of their assets as Critical Assets, their assets (or a portion thereof) do not meet the definition of a Critical Asset and should be excluded from applicability of CIP-003 through CIP-009. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. In addition, the SDT believes that having an exception process to the criteria presents the same challenges associated with a risk-based assessment in external review and oversight. | | | | |
| Gregory Van Pelt | California ISO | 2 | Abstain | The standard as written is flawed in that Applicability for this standard should be clearly stated to only include owners of the facilities or assets involved (i.e., "Critical Assets"). For example, broad sweeping designation of Transmission Operators or Balancing Authorities, as "Responsible Entities" is inappropriate in cases where they do not own the "Critical Assets". This creates undue and duplicative burden without benefit. Requirements should be revised to note a Responsible Entity is only a Responsible Entity for assets that it owns. The standard is an improvement |

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| | | | | in that clear criteria for designation of "Critical Asssets" is beneficial to consistent application and enforcement. |
| **Response**: Thank you for your comments. The Applicability section of the standard specifies to which NERC Registered Entities the standard applies. All Requirements apply to all Entities listed in the Applicability section. Each requirement uses the phrase “its … Assets” to designate ownership. | | | | |
| Barry Lawson | National Rural Electric Cooperative Association | 4 | Abstain | Please see NRECA submitted comments for reasons for abstaining during this ballot. If hte standard is modified as requested in our comments, we can vote in the affirmative. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |
| Joanna Luong-Tran | TransAlta Centralia Generation, LLC | 5 | Abstain | TransAlta sumbitted comments to explain our abstain. |
| **Response**: Thank you for your comments. Please refer to the response to comments document. | | | | |

End of Report