NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2013-02 Paragraph 81

The Paragraph 81 Drafting Team thanks all commenters who submitted comments on the Project 2013-02 Paragraph 81 - Retirement of Reliability Standard Requirements. The complete set of standards with proposed retirements for Phase 1 were posted for a 30-day public comment period from August 3, 2012 through September 4, 2012. Stakeholders were asked to provide feedback on the set of standards through a special electronic comment form. There were 43 sets of comments, including comments from approximately 98 different people from approximately 65 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Lee Pedowicz	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Ben Wu	Orange and Rockland Utilities	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Donald Weaver	New Brunswick System Operator	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Brian Robinson	Utility Services	NPCC	8
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5

				1	2	3	4	5	6	7	8	9	10
2.	Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1
2.	Bob Jones	Southern Company Services	SERC	1
3.	Pat Huntley	SERC	SERC	10
4.	Darrin Church	TVA	SERC	1

				1	2	3	4	5	6	7	8	9	10
3.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

No additional members listed.

				1	2	3	4	5	6	7	8	9	10
4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tedd	Snodgrass	WECC	1
2.	Tim	Loepker	WECC	1
3.	Erika	Doot	WECC	3, 5, 6
4.	Alfredo	Bocanegra	WECC	1

				1	2	3	4	5	6	7	8	9	10
5.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		RFC	5, 6
2.	Mike Garton		NPCC	5, 6
3.	Randi Heise		MRO	5, 6
4.	Mike Crowley		SERC	1, 3

NERC

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michelle Corley	Cleco Power	SPP	1, 3, 5
2.	Eric Ervin	Westar Energy	SPP	1, 3, 5, 6
3.	Greg Froehling	Rayburn Country Electric Cooperative	SPP	3
4.	Jonathan Hayes	Southwest Power Pool	SPP	2
5.	Louis Guidry	Cleco Power	SPP	1, 3, 5
6.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
7.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
8.	John Mason	City of Independence, MO	SPP	3
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
10.	Patrick Smith	Westar Energy	SPP	1, 3, 5, 6
11.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Godfrey	Pepco Holdings Inc	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 5
2.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
3.	Bill Watson	Old Dominion Electric Cooperative	SERC	3, 4

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Mark S. Gray	The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA)	X		X	X	X	X	X	X		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			(collectively, the Trade Associations).										
www.eei.org/ for members													
10.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E and KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5
5.	Elizabeth A. Davis	PPL Energy Plus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

11.	Group	Steve Rueckert	Western Electricity Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Phil O'Donnell	WECC	WECC	10
2.	Brent Castagnetto	WECC	WECC	10
3.	Tim Reynolds	WECC	WECC	10
4.	Tyson Jarrett	WECC	WECC	10

12.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
13.	Individual	Al DiCaprio	SRC		X								
14.	Individual	Ron Donahey	Tampa Electric Company	X		X		X	X				
15.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
16.	Individual	Scott McGough	Georgia System Operations Corporation			X	X						
17.	Individual	Ronnie C. Hoeinghaus	City of Garland	X		X							
18.	Individual	Dan Miller	Entergy Services, Inc.	X		X			X				
19.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Michelle Clements	Wolverine Power Supply Cooperative, Inc.	X									
21.	Individual	Thomas C. Duffy	Central Husdon Gas & Electric Corporation	X		X							
22.	Individual	John Tolo	Tucson Electric Power	X									
23.	Individual	paul haase	seattle city light	X		X	X	X	X				
24.	Individual	Thad Ness	American Electric Power	X		X		X	X				
25.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
26.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
27.	Individual	Laura Lee	Duke Energy	X		X		X	X				
28.	Individual	Rich Salgo	NV Energy	X		X		X					
29.	Individual	John Falsey	Edison Mission Marketing & Trading					X					
30.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
31.	Individual	Michelle R. D'Antuono	Occidental Energy Ventures Corp.			X		X		X			
32.	Individual	Patrick Brown	Essential Power, LLC					X					
33.	Individual	Becky Stewart	Idaho Power Company	X		X							
34.	Individual	Kimberly Tolbert	Occidental Power Services, Inc.			X							
35.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
36.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
37.	Individual	Eric Olson	Transmission Agency of Northern California	X									
38.	Individual	Kirit Shah	Ameren	X		X		X	X				
39.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
40.	Individual	Kristin Iwanechko	NERC Staff Technical Review										
41.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
42.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
43.	Individual	Judy VanDeWoestyne	MidAmerican Energy Company	X		X		X	X				

1. Do you agree with the criteria listed in the SAR to identify Reliability Standard requirements for retirement? If not, please explain in the comment area.

Summary Consideration:[2]

The majority of commenters supported the Criteria A, B and C included in the draft SAR, with a few commenters suggesting changes.

A. <u>Comments on Criterion A</u>

The P81 standards drafting team (P81 SDT), in conjunction with NERC's technical staff review, believes it is appropriate to rephrase Criterion A to be similar to Criterion B 9, which comports with the FFT Order, and, at the same time, to eliminate Criterion B 8 and Criterion B 9 to avoid any confusion between Criterion A and Criterion B. The P81 SDT believes the following provides a more suitable overarching Criterion A:

"The Reliability Standard requirement requires responsible entities to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES."

Comments

The Western Electricity Coordinating Council (WECC) and Northeast Power Coordinating Council (NPCC) requested clarification or alternative wording of Criterion A, while Independent Electricity System Operator and NPCC also saw Criterion A and Criterion B 9 as redundant or duplicative. Manitoba Hydro also believed there was a need to clarify Criterion B 9 and Occidental Energy Ventures Corp. desires that Criterion A implicate Section 215 of the Federal Power Act, while Occidental, like others, also believes Criterion B 8 and Criterion B 9 need clarification.

Response

The P81 SDT believes the above revision of Criterion A and elimination of Criterion B 8 and Criterion B 9 addresses the commenters' concerns, while still including the Section 215 term reliable operation.

B. <u>Comments on Criterion B</u>

[2] Although responses to informal comments are not required in the detail found in the P81 SDT responsive comments, the P81 SDT believed it was appropriate to provide more detail given the level of interest in this Standards Development Project. The format and detail of these responses are not precedent setting with respect to how other SDTs respond to an informal comment period.

Comment

WECC states it only agrees with Criterion B 1 if each administrative requirement meets all the sub-requirements listed (administrative in nature, does not support reliability and needlessly burdensome). In addition, ACES Power Marketing Standards Collaborators states that in Criterion B 1 it would be best to strike "and is needlessly burdensome."

Response

The list of requirements was meant to apply to each candidate and uses the term "and" not "or" to ensure all three are required. The wording of Criterion B 1 was carefully considered in the collaborative process, and it was believed that the current wording, which tends to match with WECC's understanding, is appropriate. Thus, the P81 SDT believes that no changes to Criterion B 1 are necessary.

Comment

WECC disagrees with Criteria B 3, B 4 and B 5 unless it may be demonstrated that there is no benefit to reliability at all.

Response

WECC's comment seems misaligned with FERC's intention which the P81 SDT believes was for NERC and stakeholders to investigate what requirements provide little protection to the BES, are unnecessary or redundant. WECC's approach seems much stricter and seems to suggest that if any plausible argument can be made, the requirement cannot be retired. Such an argument is not in line with the rest of the commenters and, therefore, will not be adopted. In addition, as the project proceeds through the standard drafting process, sufficient technical justifications will be put forward for industry review for each proposed requirement for retirement. The industry will have further opportunity to evaluate the technical justifications as the P81 project moves forward.

Comment

SRC believes that the SAR captures the right categories, but states that Criteria B 2 through B 5 could be sub-items of B1. In a similar light, NERC staff states there is significant overlap between Criterion B 3 (Purely Documentation) and Criterion B 5 (Periodic Updates) and these criteria could be combined. Independent Electricity System Operator and SRC also disagree with Criterion B 5.

Response

While annual reviews may be necessary, there may be other ways to ensure periodic reviews are done. Criterion B 5 was contemplated by the P81 SDT more in the context of future phases which would allow for the modification of requirements, not an easily identified retirement. Thus, while to some extent we share the concerns of SRC, NERC staff and Independent Electricity System Operator, we believe that the use of Criterion B 5 may be useful in facilitating review of further requirements by the stakeholders.

Comment

WECC disagrees with the use of Criterion B 2 because data and evidence collection is necessary to demonstrate compliance.

Response

The P81 SDT believes that this concern appears to miss the essential aspect of the P81 project in its initial phase which is to retire requirements that do little to protect BES reliability. Thus, hardwiring in data retention mandatory requirements does not seem aligned with generally accepted methods of auditing or promoting an effective and efficient ERO. It is incumbent on the entities to maintain sufficient evidence to support compliance with requirements, and the P81 SDT believes that any requirements that strictly support compliance assessments without a benefit to reliability should be evaluated for revision or retirement.

Comment

WECC disagrees with Criterion B 7 because it would allow other regulators to enforce a requirement.

Response

The P81 SDT agrees with WECC's overarching concern; however, that situation exists today. If there is a requirement that is already part of a regulatory order or under the purview of another governmental authority and is consistently understood and applied across North America, then the P81 SDT believes it should remain a candidate for retirement to remove this potential for double jeopardy. It is important to note, however, that it must be consistently covered across the whole continent and mandatory so as to ensure no "gaps" exist.

Comment

Independent Electricity System Operator suggests that another word be used other then "Technical" to describe Criterion B.

Response

Based on this concern, the P81 SDT changed "Technical" to "Identifying."

C. <u>Comments of Criterion C</u>

Comment

WECC believes Criterion C 1, C 2, C 4, C 6 and C 7 all need to be made more specific or improved.

Response

The concern seems predicated on Criterion C determining whether or not to retire a requirement, which is not the intent. Instead, these criteria will be used to ensure additional pertinent information and considerations are used to assist in the determination of whether a Reliability Standard requirement satisfies both Criterion A and Criterion B. The P81 SDT shall consider these data and reference points to make a more informed decision. Also, note that these criteria are conceptual only and were developed to assist the industry and the P81 SDT with their analysis. The P81 SDT thanks WECC for their thorough review; however, it will retain the criteria as written.

Comment

Independent Electricity System Operator states it is confusing as to how the section C, "Additional Data and Reference Points" will be used by the drafting team to determine retirement of Reliability Standards even though they have satisfied Criterion A and Criterion B.

Response

The P81 SDT believes that a review of the technical white paper, which will be issued and will contain the initial list of requirements to be retired, will promote an understanding on how Criterion C was used. Criterion C is only meant to provide additional considerations to provide further justifications that the proposed retirements do not have any other underlying reliability related need.

D. <u>Miscellaneous Comments on Phase I vs. Subsequent Phases</u>

Comment

ACES Power Marketing Standards Collaborators suggest that the scope of the SAR should be changed to include current standards under development.

Response

At this time it appears that including requirements from current standards under development would overly complicate the P81 project and intrude on other standard drafting teams. With that said, the P81 SDT does intend to work with and coordinate with other standard drafting teams to help ensure that new requirements are not being drafted that appear to meet the P81 criteria. Also, the P81 SDT will be working with the Standards Committee to draft guidelines to help standard drafting teams draft requirements that are more results-based, and not requirements that would meet the P81 criteria.

Comment

ERCOT indicates that the criteria used for future phases should remain flexible.

Response

The initial list should not preclude the use of additional criteria for future phases where additional criteria support the elimination of requirements in those efforts. Given the amount of commenters who requested numerous requirements be considered in future phases, it appears reasonable that P81 project should remain flexible to meet the needs of stakeholders. Thus, the P81 SDT has revised the SAR to apply to Phase I only.

Comment

SRC urges the SAR simply suggest that the proposed requirements be considered and evaluated by the SDT as opposed to making a presumption (and hence setting a high expectation for the industry) that the proposed list will be retired.

Response

The P81 SDT did not intend for the list of requirements proposed in the draft SAR to come across as a list without flexibility.

Comment

ACES Power Marketing Standards Collaborators suggests that requirements that are assigned to the wrong functional entities should be added as a criterion for revision or retirement.

Response

The P81 SDT believes that ACES's suggestion should be considered during the development of a Phase 2 SAR. In many instances, applicability can be a complex undertaking and there may be large diversity, irrespective of an entity having some common high-level responsibilities as listed in the NERC Registry and Functional Model.

Comment

NERC staff suggests that any technical justifications that rely on Criterion B 6 should address how NAESB, etc. would handle the requirement.

Response

As a general matter, many commenters suggest that the P81 project develop thorough justifications and remain in line with the suggested Criteria. NERC staff's concern of reliance on Criterion B 6 will also be considered when developing the justifications. The P81 SDT removed references to NAESB, but notes that when relying on B 6, sufficient reference will be made to other mandatory requirements which effectively ensure there will be no gap on a continent-wide basis and in addition, what will ensure that on an ongoing basis, this gap will remain addressed by something other than a NERC standard requirement. The technical white paper will consider these concerns. In addition, the P81 SDT believes that ongoing training for drafting teams will ensure that these types of requirements are no longer developed.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council	No	WECC offers the following related to the criteria listed in the SAR.WECC beleives the OVERARCHING CRITERIA listed under "A" needs clarification and that as currently identified is too vague. The Overarching Criterion statement is too broad and is contrary to the FPA Section 215. “Impact” is an ambiguous term. There is no measure as to how to quantify a Requirement’s “impact” and to distinguish between “little” impacts as opposed to some other metric of “impact.” More importantly, however, a Requirement that has any impact on the reliable operation of the BES cannot be dismissed as inconsequential, even if it is determined to have “little” impact. The "impact" must be weighed against the "burden" of the standard and potential for efforts to demonstrate compliance hindering or preventing other more "impactful" reqiurements. Further, the Standard Requirements work in concert with one another. For many Standard Requirements, it is impossible to reasonably assess the “impact” of a single Standard Requirement. For example, the “purpose” statement for CIP Standard Requirements reads that “[CIP Standard Requirements] should be read as part of a group of standards numbered Standards CIP-002 through CIP-009.” To examine the “impact” of a single Standard Requirement, therefore, contradicts the intent and purpose of many Standard Requirements that are crafted to operate in concerns with one another.WECC believes the B1 Administrative Technical Criteria needs claificaiton and is vague as currently written. The term “administrative” is ambiguous and could cover a broad range of activities. Further, “administrative requirements” often require evidence of program or procedure creation. However, WECC does agree with this criteria, but only in the case where all three criteria listed (administrative, does not support reliability, and needlessly burdensome) are met.WECC disagrees witht he B2 Technical Criteria Data Collection/Data Retention. Data Collection/Data Retention is often the only means by which a Responsible Entity can objectively demonstrate compliance. As to mandatory data retention

Organization	Yes or No	Question 1 Comment
		periods, an explicit mandate to retain data may be required to meet compliance obligations unique to a particular Standard Requirement. However, if treated correctly, a requirement for the data collection/retention for compliance purposes could be removed from the Requirmeetns and made part of the Measures or RSAWs.WECC Disagrees with the B3 criteria Purley Documentation unless it can be clearly demonstrated that the dcoumentation does not protect the reliabiltity of the BES in any way. In some cases Plans/Policies/Procedures are necessary for employees to have a guide for not only protection but maintaining and restoring BES assets (i.e. Restoration Plans). Documentation of plans, policies and procedures, is key in defining the parameters of compliance. Further, plans/policies and procedures are often the only means by which Compliance and Enforcement can assess a responsible entity's compliance with a Standard Requirement.WECC Disagrees with the B4 criteria Purely Reporting unless no purpose for the reporting can be identified. Reporting helps overarching organizations (ex. ES ISAC) detect potential issues earlier, by giving them more information and from multiple entities. These issues may seem small or insignificant when viewed by a singular entity but may have a more a drastic impact when viewed from the perspective of the entire BES. WECC Disagrees with the B5 criteria Periodic Updates unless it can be clearly demonstrated that the reproting has no operational benefit to reliability. Without these requirements there is nothing in place to ensure entityies are maintaining, and periodically verifying the accuracy of these documents. With the criteria established as it is, there is no real way of measuring the effect of "operational benefit to reliability". Is it measured by the size of impact (MW), by time (something that will take over a 1hr), or by Time Horizon (Same-Day operations vs. Real Time Operations). It is recommended to establish a more accurate means to measure these criteria. If proberly handled, these reporting requirements that that demonstrate the entities are maintaining certain necessary

Organization	Yes or No	Question 1 Comment
		documents could be moved from the Requirements to the Measures or RSAWs.WECC agrees with the B6 criteria of Business Practices.B7 criteria Redundant: Although WECC agrees requirements should not be redundant with each other, if compliance is left to other regulators (Open Access Transmission Tariff, NAESB, etc.) compliance may not be held up to NERC expectations or interpretations. In identifying redundant standards, only NERC Reliability Standards should be considered.WECC agrees with B* criteria,WECC believes the B9 criteria needs clarification and as written is vague. How will the determination that teh Requirements do little, if anything, to promote the protection of the BES be determined?WECC disagrees with C1. The FFT determination is not predicated on any particular Standard Requirement. The FFT determination is fact specific. Even a requirement that is critical to the BES may have an FFT'd violation if the manner in which the requirement was violated was minor.WECC beleives C2 is vague and needs clarification. Not certan what it means if the requirement is being revieweed in an on-going Standards Development Project. Is this the same as B7 Redundant?WECC agrees C3 is a factor that should be considered.WECC agrees with C4 but beleives information on how the tiers will be viewed should be included.WECC agrees with C5.WECC believes C6 and C7 are vague as written and believes that these last two reference points are intended to indicate that if the answer is yes, then the requirement or standard would NOT be eligable for retirement. This should be clarified.
Independent Electricity System Operator	No	(1) The IESO supports this proposed effort and agrees with most of the criteria, with some exceptions (except #5): "The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability."Take for example the system restoration plan. An annual review is necessary to ensure that the plan recognizes BES facility changes that occurred since the last review/update. Another

Organization	Yes or No	Question 1 Comment
		example is the exceptions to the cyber security policy that needs to be reviewed and approved by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Applying this criterion in a broad brush manner without looking at each requirement may result in removing requirements that are still needed for reliability.(2) Generally, the nine criteria listed in the SAR are simple and sufficient to be used to determine retirement of reliability standard requirements. It is recommended that the word “Technical” in the heading of the B section “Technical Criteria” be erased as the criteria aren’t based on technical data. Also, it is unclear and confusing as to how the section C “Additional Data and Reference Points” will be used by the drafting team to determine retirement of reliability standards even though they have satisfied Criteria A and B. Criterion B.9 can potentially be deleted as its purpose seems to be the duplication of Criterion A.(3) The SAR narrative for TOP-001-1a R3 states the requirement is redundant with IRO-001-1a R8. IRO-001-1a does not exist; we believe, it should be IRO-001-1.1 R8 instead.
NERC Technical Staff Review	No	(1) Revise Criteria A to focus on the content of the Reliability Standards. NERC Staff suggests the following language for Criteria A: “The Reliability Standard requirement requires responsible entities to conduct an activity or task that does little, if anything, to protect reliable operation of the BES.” This language is currently included as Criteria B9. NERC notes that both Criterion B8 (hinders the protection or reliable operation of the BES) and B9 (little, if any value as a reliability requirement) are duplicative with Criterion A and should be eliminated. Since any requirement that meets Criterion B8 or B9 would necessarily meet Criterion A, this creates an unintended consequence by undermining the objective that requirements for consideration must satisfy both the overarching Criterion A and a separate technical criteria. For these reasons, NERC Staff supports the elimination of both Criteria B8 and B9 and the re-phrasing of Criteria A. (2) There is significant overlap between Criteria B3 (Purely Documentation) and B5

Organization	Yes or No	Question 1 Comment
		(Periodic Updates) and these criteria could be combined. Criteria B3 addresses requirements for entities to develop a document that is not necessary and Criteria B5 addresses the requirement for entities to periodically update such documentation. NERC Staff suggests renaming Criteria B3 "Documentation" and suggests the following language: "The Reliability Standard requirement requires responsible entities to develop and/or periodically update a document (e.g., plan, policy or procedure) which is not necessary to protect BES reliability." (3) The explanation of Criterion B6 (Commercial or Business Practice) states that the Reliability Standard requirement "is a commercial or business practice, e.g., better served as a NAESB standard or as part of NAESB Electric Industry Registry (EIR)." However, the technical justifications provided for the application of the B6 criteria do not state that the standard/requirement should be addressed in another manner, e.g., with a NAESB standard. Please clarify or otherwise modify this criterion appropriately. Further, the technical justification should address the fact that such business practices may not be applicable to the same entities and may not be mandatory or enforceable.
Northeast Power Coordinating Council	Yes	NPCC participating members support the P81 initiative and agree with the criteria listed in the SAR to identify Reliability Standard requirements for retirement. The criteria are also consistent with FERC's guidance in Paragraph 81 of the FFT Order. With respect to the words in Criterion A wording, it could be interpreted as an indication that the original reliability standard requirement was a mistake. Suggest the SDT consider alternative wording to indicate that the experience with the requirement, over time, has proven not to be useful to accomplish its initially intended reliability objective, or has not produced clear results for the initially intended reliability objective.Criterion A, and Technical Criteria B9 "Little, if any, value as a reliability requirement" are redundant.

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	Yes	In general, we agree with the criteria. However, we do offer two suggestions. First, in criterion B.1, we suggest striking “and is needlessly burdensome”. If the activity does not support reliability the burden is irrelevant. Second, we suggest if there are current standards under development that are already proposing to retire requirements that those requirements should be considered for inclusion in this project. In order to include those requirements, the proposed reason for retirement should align with one of the criteria in this project. This would accelerate the retirement of unnecessary requirements. Third, we suggest requirements that are assigned to the wrong functional entities should be added as a criterion for revision/retirement.
The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA) (collectively, the Trade Associations).	Yes	The Trade Associations agree with the criteria listed in the SAR to identify Reliability Standard requirements for retirement. As noted above, the criteria were the product of intense discussions among numerous stakeholders, including the Trade Associations, NERC, and the Regional Entities. The criteria are also consistent with FERC’s guidance in paragraph 81 of the FFT Order.
SPP Standards Review Group	Yes	We concur that the proposed criteria are a good starting point for the evaluation of requirements to be retired.
Salt River Project	Yes	We like the criteria and methodology.

Organization	Yes or No	Question 1 Comment
SRC	Yes	The criteria listed in the SAR capture the right categories; however, consider restructuring B1. B2 through B5 are examples of administrative requirements and should possibly be sub-items of B1. While we generally support this proposed effort and agrees with most of the criteria, the exception is B5: “The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.”Take for example the system restoration plan. An annual review is necessary to ensure that the plan recognizes BES facility changes that occurred since the last review/update. Another example is the exceptions to the cyber security policy that needs to be reviewed and approved by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Applying this criterion in a broad brush manner without looking at each requirement may result in removing requirements that are still needed for reliability. In addition, the acid test for retirement of a requirement is when the standard drafting team reviews the overall reliability impact of removing a particular requirement from a standard, and how it may affect other related standards. In brief, it may be a bit premature to pass on this judgment at the SAR stage. We urge the SAR proponent to simply suggest that the proposed requirements be considered and evaluated by the SDT as opposed to making a presumption (and hence setting a high expectation for the industry) that the proposed list will be retired. And, in order to meet the requirements for regulatory approval, we suggest the SDT to provide strong technical basis to justify each retirement.
Manitoba Hydro	Yes	The technical criteria B.9, "Little if any, value as a reliability requirement", is very subjective and should be redefined or clarified.
Georgia System Operations Corporation	Yes	Georgia System Operations agrees with the criteria listed in the SAR to identify Reliability Standard requirements for either modification or

Organization	Yes or No	Question 1 Comment
		withdrawal.
seattle city light	Yes	Seattle City Light supports the consolidated comments of the industry Trade Organizations.
NV Energy	Yes	We agree with the Overarching Criterion and the specific Technical Criteria, and believe that the types of requirements specified in the Technical Criteria can be eliminated without any impact to reliable operation of the interconnected transmission system.
Occidental Energy Ventures Corp.	Yes	Occidental Energy Ventures Corp. ("OEVC") fully supports the efforts taken by the Trades, NERC, and the Regional Entity Management Group to develop the criteria to identify requirements that may be eligible for retirement and modification. The overarching criterion is extremely important in our view, as it serves to remind us all that FERC's original purpose as defined by Section 215(a)(4) of the Federal Power Act is to oversee wide-area reliability of the bulk power system. In recent years, the Commission's authority has expanded into distribution systems and localized load shedding - important issues, but already regulated by the PUCs. In our view, this is duplicative work that increases costs without serving improved reliability.OEVC also believes that the technical criteria are appropriate and complete for now. However, in our view, Item #8 "Hinders the protection or reliable operation of the BES" and Item #9 "Little, if any, value as a reliability requirement" will need further refinement in future phases of this project. Both are quite subjective, and FERC in our opinion will only respond to fact-based quantitative data that shows that BPS reliability is not improved by a given reliability requirement. A painful reminder may be the requirement for secondary Facility Ratings (FAC-008-3) which FERC clearly perceives to be a reliability imperative despite overwhelming industry rejection of the concept. It is unlikely that this view will change unless tangible cost/benefit evidence to the contrary

Organization	Yes or No	Question 1 Comment
		is provided to the Commission.
South Carolina Electric and Gas	Yes	I support removing redundancy and any items that are not related to reliability impacts.
Georgia Transmission Corporation	Yes	Georgia Transmission Corporation agrees with the criteria listed in the SAR to identify Reliability Standard requirements for either modification or withdrawal.
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the ISO/RTO SRC comments. However, in addition for SRC comments, ERCOT offers the following: ERCOT agrees with the criteria listed in the SAR to identify Reliability Standard requirements for retirement in Phase 1. However, the criteria used for future phases should remain flexible. The initial list should not preclude the use of additional criteria for future phases where additional criteria support the elimination of requirements in those efforts.
SERC EC Planning Standards Subcommittee	Yes	
Southwest Power Pool Regional Entity	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
Pepco Holdings Inc & Affiliates	Yes	
PPL Corporation NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 1 Comment
Tampa Electric Company	Yes	
City of Garland	Yes	
Entergy Services, Inc.	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Central Husdon Gas & Electric Corporation	Yes	
Tucson Electric Power	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
CPS Energy	Yes	
Duke Energy	Yes	
Edison Mission Marketing & Trading	Yes	
Illinois Municipal Electric Agency	Yes	
Essential Power, LLC	Yes	
Idaho Power Company	Yes	
Occidental Power Services, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
City of Austin dba Austin Energy	Yes	
Transmission Agency of Northern California	Yes	
Ameren	Yes	
Kansas City Power & Light	Yes	
MidAmerican Energy Company	Yes	

2. The Initial Phase of the P81 project is designed to identify all FERC-approved Reliability Standard requirements that easily satisfy the criteria. Do you agree that the suggested list of Reliability Standard requirements included in the draft SAR easily satisfy the criteria listed in the draft SAR? If you disagree, please provide a statement supporting what Reliability Standard requirements you would add or subtract from the Initial Phase, including a citation to at least one element of Criterion B, as applicable.

Summary Consideration:

A. Support for Initial List

The majority of commenters support the initial list of requirements suggested for retirement in the draft SAR. Supporters include SPP Standards Review Group, The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC), the Canadian Electricity Association (CEA) (collectively, the Trade Associations), Salt River Project, SRC, Georgia System Operations Corporation, Seattle City Light, Duke Energy, NV Energy, Occidental Energy Ventures Corp., South Carolina Electric and Gas, Ameren, Electric Reliability Council of Texas, Inc., SERC EC Planning Standards Subcommittee, Dominion, Pepco Holdings Inc & Affiliates, PPL Corporation NERC Registered Affiliates, Tampa Electric Company, Manitoba Hydro, City of Garland, Entergy Services, Inc., Wolverine Power Supply Cooperative, Inc., Central Hudson Gas & Electric Corporation, Tucson Electric Power, CPS Energy, Edison Mission Marketing & Trading, Illinois Municipal Electric Agency, Idaho Power Company, City of Austin dba Austin Energy, Transmission Agency of Northern California, and Kansas City Power & Light. Also, the following entities appear to generally support the current list, while requesting additional requirements to be added: Georgia Transmission Corporation, Occidental Power Services, Inc., American Electric Power, and ACES Power Marketing Standards Collaborators. This level of support appears to be a testament to the hard work of the collaborative process and provides significant context in which to consider the merits of those stakeholders who requested that certain requirements be added or removed from the initial list.

B. Concerns with requirements included in the initial list

Comment

Northeast Power Coordinating Council (NPCC), Southwest Power Pool Regional Entity (SPP RE), Western Electricity Coordinating Council (WECC), NERC staff technical review (NERC staff) presented concerns with retiring requirements related to PRC-008-0 and PRC-009-0.

Response

As SRC points out, PRC-009-0 is already scheduled to be retired. More specifically, in Order No. 763 at Paragraph 103[3] the Commission accepted the retirement of PRC-009-0 as appropriately replaced with PRC-006-1. Consistent with Order No. 763, PRC-009-0 will become inactive on September 30, 2013 and will be replaced by PRC-006-1. Similarly, under Standards Development Project 2007-17 Protection System Maintenance, which recently passed stakeholders vote on August 27, 2012, PRC-008-0 is scheduled to be retired and replaced with PRC-005-2. PRC-005-2 will likely be presented to the NERC Board of Trustees in November for approval. To avoid confusion and promote regulatory efficiency, the P81 SDT intends to present PRC-008-0 and PRC-009-0 in the final SAR for informational purposes only. Accordingly, PRC-008-0 and PRC-009-0 will not be included in the P81 project for purposes of comment and ballot.

Comment

NPCC is concerned that it may only receive information related to UVLS program assessment and performance after an event if PRC-010-0 R2 and PRC-022-1 R2 are retired.

Response

The P81 SDT believes it is appropriate to retire PRC-010-0 R2 and PRC-022-1 R2 because the Regional Entities' current compliance and monitoring processes provide for the review of UVLS program assessment and performance during a spot check, compliance audit, etc., which makes PRC-010-0 R2 and PRC-022-1 R2 unnecessary. Thus, the P81 SDT believes that PRC-010-0 R2 and PRC-022-1 R2 should remain within the scope of P81 for purposes of comment and ballot.

Comment

WECC and SPP RE requested that CIP-007-3 R7.3 not be retired, based on concerns related to demonstrating compliance with other requirements.

Response

These concerns appear to miss the essential aspect of the P81 project which is to retire requirements that do little to protect BES reliability. The P81 SDT believes that data retention in and of itself has little to do with protecting BES reliability, particularly when the Regions have authority to request data to show compliance with any mandatory Reliability Standard. Thus, hardwiring in data retention into mandatory Reliability Standard requirements does not seem aligned with generally accepted methods of auditing or promoting an effective and efficient ERO compliance program. In other words, it seems to adopt the position of WECC and SPP RE on this matter could essentially be an endorsement that every Reliability Standard requirement should be accompanied with a mandatory data retention requirement, which would seem counterintuitive given the processes set for in the Compliance Monitoring and Enforcement Program. Thus, the P81 SDT believes that CIP-007-3 R7.3 should remain within the scope of P81 for purposes of comment and ballot.

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[3] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 F.E.R.C. ¶ 61,098 (2012).

Comment

WECC also disagrees with the inclusion of IRO-016-1 R2 with a concern that Reliability Coordinators must be required to document their actions for compliance and enforcement purposes.

Response

Reliability Coordinator actions are conducted over recorded lines or via written directives, and, thus, the documentation is already available for a Regional Entity to inspect. Further, during a spot check or compliance audit a Regional Entity has the authority to request information, as well as the entity has the burden to prove compliance – if the entity chooses to prove compliance via recorded phone lines or logs is not necessarily an appropriate subject for a mandatory Reliability Standard. Thus, the P81 SDT believes that IRO-016-1 R2 should remain within the scope of P81 for purposes of comment and ballot.

Comment

WECC and NERC staff express concerns with including MOD-004-1. Specifically, WECC states:

MOD-004 is not redundant to TOP-002 even though the CBM itself may be a tariff issue and rarely used. The reliability piece is that if the CBM is used by a TSP then the details of it must be available for use in system studies. Without the awareness of a transmission holdback for CBM when it exists, a network study could be run and show no issues but if at some time the CBM were implemented an overload could result. This might not always be the case but unless the CBM parameters are known and modeled it could impact reliability.

NERC staff suggests that MOD-004-1 may be more appropriate for a subsequent phase unless a solid technical justification can be developed for MOD-004-1 that addresses relevant FERC's ruling.

Response

One of the tenants of the initial phase of P81 is that the requirement does not need significant technical justifications or editing. Notwithstanding the apparent support for MOD-004-1 to be part of the P81 project, it is also apparent to the P81 SDT that at this time MOD-004-1 needs additional review and consideration prior to any decision to retire all or part of its requirements. It is also noteworthy that there are a large number of requests to consider other MOD standards in subsequent phases, and it is likely appropriate to consider the MOD Standards as a whole so that MOD-004-1 can be more thoroughly analyzed. For example, CBM is referenced in a number of MOD Standards, such as MOD-001-1a, MOD-008-1 and MOD-028-1. Thus, the P81 SDT has removed MOD-004-1 from the list of requirements proposed for the initial phase and MOD-004-1 will be considered in a subsequent phase of the P81 project.

Comment

WECC, Public Service Enterprise Group and Essential Power, LLC state that CIP-002-1a R4 should not be retired. WECC makes several points, including:

"An entity has many enforcement agencies to contact without the FBI listed in the operating instructions they could easily be overlooked. . . . . Retiring R4 will remove the incentive of having a working relationship with the FBI, especially among the smaller entities. Retiring R4 may effectively delay or prevent the FBI from rapidly locating those responsible for sabotage."

Also, Public Service Enterprise Group and Essential Power, LLC state:

"If the entity owns or operates a BES asset, there is a clear reliability benefit to have appropriate law enforcement contacts and procedures to address sabotage or other security incidents. Similarly, the federal agencies feel that this is a good idea. In a coordinated attack environment, sabotage reporting to these Law enforcement agencies from the BES operators and owners would improve the ability of a coordinated response."

Response

The P81 SDT believes that the practices and procedures discussed by WECC, Public Service Enterprise Group and Essential Power, LLC are accomplished via R1 through R3 of CIP-002-1a, not R4. For example, consistent with R2,[4] it is common practice to contact local law enforcement authorities when there is any suspicion that sabotage has occurred at a BES facility. The entity's corporate security and site personnel will consult with local law enforcement to assess the situation and facts to determine whether a suspected or actual act of sabotage has occurred. If they find a suspected or actual act of sabotage has occurred, reliability entities as well as the Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP), as appropriate, will be contacted in accordance with R2. Thus, pursuant to R1 through R3, when there is an instance of sabotage that warrants contacting the FBI or RCMP or any other federal or national governmental authority, entities will contact them. Conversely, the requirement in R4 to establish communication contacts with the FBI or RCMP, as applicable, is purely an administrative, documentation and data collection task requirement – there is no operational or results-based aspect of R4, like there is with R1 through R3. Accordingly, in CIP-001-2a R1 through R3 serve the results-based reliability function, while R4 is a static, administrative requirement that has no direct or clear nexus to protecting BES reliability. For these reasons, the P81 SDT believes that CIP-001-2a R4 should remain within the scope of P81 for purposes of comment and ballot.

Comment

Bonneville Power Administration, WECC and NERC staff do not support the proposed retirement of TOP-001-1a R3.

[4] "**R2.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection."

Response

Bonneville Power Administration, WECC and NERC staff all make valid points. Although there is redundancy between TOP-001-1a R3 and IRO-001-1a R8 related to Reliability Coordinators, this redundancy was addressed in Standards Development Project 2007-03 (Real-time Operations). Specifically, Project 2007-03 eliminated the redundancy in the current version of TOP-001-2 R1 that replaces TOP-001-1a R3 and reads as follows:

Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements.

TOP-001-2 has been approved by the NERC Board of Trustees and will be filed with the Commission for approval; therefore, the P81 SDT intends to present TOP-001-1a R3 in the final SAR for informational purposes only. Accordingly, TOP-001-1a R3 will not be included in the P81 project for purposes of comment and ballot.

Comment

SRC and NERC staff state that VAR-002-WECC-1 R2 and VAR-501-WECC-1 R2 should not be included in the P81 project until they have first been processed for retirement via the WECC regional standards process.

Response

SRC and NERC staff make a valid point that regional standards proposed for retirement need to first proceed through their region prior to being considered for retirement via a NERC standards development project. For these procedural concerns, VAR-002-WECC-1 R2 and VAR-501-WECC-1 R2 have been removed from the P81 project; however, the P81 SDT encourages WECC to consider the deliberations of the collaborative process and act on retiring VAR-002-WECC-1 R2 and VAR-501-WECC-1 R2, as appropriate.

Comment

Central Hudson Gas & Electric Corporation, Public Service Enterprise Group, and American Electric Power and Essential Power, LLC express concern with the inclusion of CIP-003-3 R4 and its sub-requirements in the P81 project. AEP states:

“AEP recommends instead that CIP-003 R1 be removed in which case CIP-003 R3 (and CIP-003 R2.4) can also be removed. However, if the drafting team does not agree with this recommendation, CIP-003 R3 must be retained in order for entities to take targeted exception(s) where applicable (for example, in circumstances where an entity’s program is more stringent than the CIP requirements).”

Public Service Enterprise Group and Essential Power, LLC indicate that “[t]he exceptions language in R3, though rarely used, allows for those instances where an entity is unable to conform with it's cyber security policy.”

Response

The reason for retiring CIP-003-3, -4 R3 and its sub-requirements is directly applicable to the concerns expressed. In other words, although the CIP exception requirements have never been available for use to exempt an entity from compliance with any requirement of any NERC Reliability Standard, entities apparently are reading the CIP exception requirements out of context. These requirements only apply to exceptions to internal corporate policy, and only in cases where the policy exceeds a NERC Reliability Standard requirement or addresses an issue that is not covered in a NERC Reliability Standard. For example, if an internal corporate policy statement requires that all passwords be a minimum of eight characters in length, and be changed every 30 days, this provision could be used for internal governance purposes to lessen the corporate requirement back to the password requirements in CIP-007 R5.3, or in conjunction with a Technical Feasibility Exception (TFE) to something else. Therefore, removal of this requirement has no effect on the TFE process or compliance with any other CIP requirement. Also, the retirement of the CIP exception requirements would not impact an entity's ability to maintain such a process within their corporate policy governance procedures. Consequently, the CIP exception requirements provide little protection for BES reliability and are an internal administrative and documentation requirement that is outside the scope of the other CIP requirements. Thus, the P81 SDT believes that CIP-003-3, -4 R3 and its sub-requirements should remain within the scope of P81 for purposes of comment and ballot.

Comment

Public Service Enterprise Group and Essential Power, LLC also request the P81 project not include EOP-004-1 R1 because it will soon be replaced by EOP-004-2.

Response

The P81 SDT notes that the past ballot of EOP-004-2 did not pass and it is currently in the balloting stage. The P81 SDT has coordinated its efforts with the chair of Project 2009-01 and both agree there is no conflict between retiring EOP-004-1 R1 and the direction of Project 2009-01. At such time that the EOP-004-2 project does obtain stakeholder approval and is scheduled for NERC Board of Trustees review, P81 SDT will reconsider the need to include EOP-004-1 R1. Thus, at this time, the P81 SDT believes that EOP-004-1 R1 should remain within the scope of P81 for purposes of comment and ballot.

Comment

Public Service Enterprise Group and Essential Power, LLC further request that FAC-002-1 R2 be removed from the P81 project based on the concern that the three year study retention requirement could be increased to six years via compliance and monitoring data retention.

Response

The concern of Public Service Enterprise Group and Essential Power, LLC, however, appears to miss the essential aspect of the P81 project in its initial phase which is to retire requirements that do little to protect BES reliability. Thus, hardwiring in data retention mandatory requirements does not seem aligned with generally accepted methods of auditing or promoting an effective and efficient ERO compliance program. Accordingly, the P81 SDT believes that FAC-002-1 R2 should remain within the scope of P81 for purposes of comment and ballot.

Comment

NERC staff questioned the inclusion of FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 in the P81 project. Specifically, NERC staff states:

"These requirements, combined with others, provide checks and balances on the Facility Rating Methodology and Transfer Capability methodology established by the responsible entities. This provides a reliability benefit by requiring the responsible entity to consider areas in which their methodology may not be sufficient to support reliable operation of the interconnected transmission system. There may be better ways of assuring that entities have sufficient methodologies and alternatives should be considered during Phase II. NERC Staff suggests that the SDT reconsider whether discussing the methodology (and not the numerical rating of a facility) has commercial or market related implications. With respect to FAC-013-2 R3, NERC Staff suggests that the SDT reconsider whether the requirement relates to "a back and forward on transfer capability" as noted in the draft SAR, as the requirement pertains only to the methodology for determining transfer capability."

Response

The P81 SDT notes that Page 5 of NERC's Standards Process Manual states:

"A Reliability Standard includes a set of Requirements that define specific obligations of owners, operators, and users of the North American Bulk Power Systems. The Requirements shall be material to reliability and measurable."

It appears difficult to read into the plain language of FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 specific obligations that are material to reliability and measurable or provide more than a little amount of protection to BES reliability. For instance, in practice, while the owners of ratings and transmission capability methodologies have made these documents available for comment during the duration of the mandatory Reliability Standard regime, experience shows that little, if any, technical comments have not been submitted on these documents. In the regional processes, entities are on a variety of committees and have professional relationships, and, therefore, if they have a concern with a methodology, they have ample opportunity to seek out professional technical critique as a best practice. FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 seem toonly formalize a vehicle for professional technical critique without an exacting nexus between it and reliability. Given that entities that develop these methodologies must comply with rigorous requirements in FAC-008 and FAC-013, the P81 SDT believes that the addition of a mandatory best practice technical critique process does not seem necessary, material or measurable. It is also noteworthy that there is no obligation for any entity to request a methodology nor is there any obligation on the owner of the methodology to respond to any comments with any level or burden of technical thoroughness. Thus, the P81 SDT believes that FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 should remain within the scope of P81 for purposes of comment and ballot.

C. Suggested additions to the initial list

Comment

NPCC suggests adding FAC-003-1 R3, FAC-003-1 R4, CIP-005-3 R4, and CIP-007-3 R8.

Response

While the P81 SDT believes there appears to be merit in considering the FAC-003 and CIP requirements suggested by NPCC, these requirements were discussed in the collaborative process and it was generally agreed that these requirements need additional technical review prior to any consideration of retirement. Thus, these requirements will be considered in a subsequent phase of the P81 project.

Comment

NPCC and SRC suggest adding IRO-014-2 R2 and it sub-requirements. According to NPCC, these requirements are administrative requirements only and do not enhance reliability, while SRC states that these requirements satisfy Criterion B1 and Criterion B5.

Response

While IRO-014-2 R2 seems like a valid candidate for P81, it is not a FERC-approved Reliability Standard. At this time, it has been adopted by the NERC Board of Trustees and has yet to be filed with FERC for approval. As the P81 project matures or a more formalized approach to P81 is adopted by NERC in its Rules of Procedures or processes, the consideration of Reliability Standards not yet approved may be practical. However, at this time, the scope of the P81 project remains FERC-approved Reliability Standards. The exception to this is if a FERC-approved requirement being proposed for retirement is duplicated in a standard that has only been adopted by the NERC Board of Trustees. Thus, at this time, IRO-014-2 R2 is not ripe for consideration in P81.

Comment

ACES Power Marketing Standards Collaborators suggests adding FAC-010-2.1 R5 and FAC-011-2 R5 in the initial phase for the following reasons:

"FAC-010-2.1 R5 is an administrative requirement for the Planning Authority to respond to comments on its SOL methodology. Failure to provide a written response to technical comments does not impact reliability. The PC is already required to distribute its methodology in R4. Any functional entity that would have provided technical comments will see any adjustments. This requirement meets Criteria B.1 and B.9.(7) FAC-011-2 R5 is an administrative requirement for the Reliability Coordinator to respond to comments on its SOL methodology. Failure to provide a written response to technical comments does not impact reliability. The RC is already required to distribute its methodology in R4."

Response

ACES Power Marketing Standards Collaborators' position is similar to the reasons that FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 were included in the draft SAR as satisfying the criteria and appropriate for retirement. Further, the language in all of these Reliability Standard requirements is very similar. Thus, the P81 SDT has added FAC-010-2.1 R5 and FAC-011-2 R5 to the initial phase of P81.

Comment

ACES Power Marketing Standards Collaborators suggests that IRO-005-3 R11 is redundant with MOD-028-1 R6.1, MOD-029-1a R3, and MOD-030-2 R2.4 and that the MOD standards already require the Transmission Service Provider to consider IROLs and SOLs when determining Available Transfer Capability/Available Flowgate Capability and Total Transfer Capability. Specifically, IRO-005-3 R11 reads:

"The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes."

Response

It appears that while IRO-005-3 R11 may be redundant for the reasons stated by ACES Power Marketing Standards Collaborators; however, this requirement has been retired in IRO-005-4, which was approved by the Board of Trustees and is pending a filing at FERC. Thus, recognizing that that Project 2006-06 Reliability Coordination has already received many of the necessary approvals to retire IRO-005-3 R11, it does not seem to serve regulatory efficiency to include IRO-005-3 R11 in the P81 project as well. Thus, the P81 SDT did not add IRO-005-3 R11 to the initial phase of P81.

Comment

ACES Power Marketing Standards Collaborators suggests COM-001-1.1 should be retired because English is the dominant language used.

Response

To retire such a requirement would possibly need coordination with the Canadian authorities in French speaking provinces and those in areas of the United States were Spanish is a first language. Such coordination would seem to complicate the retirement of COM-001-1.1, and, thus, the P81 SDT believes it is more appropriately considered in a subsequent phase.

Comment

With regard to VAR-001-2 R5, ACES Power Marketing Standards Collaborators states that it:

". . . is redundant with FERC's pro forma tariff and was originally included in the NERC policies to align them with said tariff. The requirement compels the PSE and LSE to arrange for reactive resources to satisfy the reactive requirements of the Transmission Service

Provider. PSEs and LSEs cannot purchase transmission service without purchasing reactive service or demonstrating to the transmission provider that they have arranged for reactive resources. From a practical perspective, this means they always purchase reactive service from the Transmission Provider. Furthermore, it is the Transmission Operator that actually ensures reactive resources are dispatched per VAR-001-2 R2."

Response

The P81 SDT notes that when approving VAR-001, in Order No. 693 at Paragraph 1858,[5] the Commission recognized:

". . . that all transmission customers of public utilities are required to purchase Ancillary Service No. 2 under the OATT or self-supply, but the OATT does not require them to provide information to transmission operators needed to accurately study reactive power needs. The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities."

ACES Power Marketing Standards Collaborators states VAR-001-2 R5 appears to be redundant with Ancillary Service No. 2 under the OATT. Moreover, VAR-001-2 R5 is very limited to this OATT obligation and regional process, and, therefore, does not speak to the Commission's concern related to providing information to Transmission Operators for accurate reactive power studies. Therefore, it appears that VAR-001-2 R5 satisfies the P81 criteria by doing little to protect BES reliability and being redundant with the OATT. Thus, the P81 SDT has added VAR-001-2 R5 to the initial phase of P81.

Comment

ACES Power Marketing Standards Collaborators also suggests adding BAL-002 R1, BAL-002 R3, BAL-005-0.1b R1 and its sub-requirements, INT-004-2 R1, and TOP-005-2a R3.

Response

The P81 SDT notes that during the collaborative process the linkage between the BAL and INT standards was discussed and there seems to be merit considering whether some BAL and INT standards could be combined. The Trade Associations, among others, suggested this be conducted in a subsequent phase of P81. Given the complexity related to the linkage between the BAL and INT standards, along with TOP-005-2a R3, the P81 SDT believes that additional review should be conducted in a subsequent phase of P81 prior to retiring the suggested BAL and INT standards.

Comment

[5] VAR-001-2 was approved via a Letter Order issued on January 10, 2011.

ACES Power Marketing Standards Collaborators also suggests including PRC-011-0 R2, PRC-015-0 R3, PRC-016-0.1 R3, PRC-017-0.1 R2, PRC-021-0.1 R2, PRC-023-1 R2, and PRC-023-2 R3. American Electric Power suggests the following additions: PRC-021-1 R2; PRC-018-1 R5; PRC-016-0.1 R3; PRC-015-0 R3; PRC-011-0 R2; PRC-007-0 R3; CIP-006 R1.5; CIP-004-3 R4; CIP-007 R5.1.1; CIP-007 R5.1.3; CIP-007 R6.3; CIP-007 R6.4; CIP-003-3, CIP-003-4 R1; CIP-003-3, CIP-003-4 R1.2; CIP-003-3, CIP-003-4 R1.3; CIP-003-3, CIP-003-4 R2.4; CIP-003-3, CIP-003-4 R3. Tampa Electric recommends that the P81 SDT ensure that the CIP requirements proposed for removal via P81 are also removed from v5 of the NERC CIP standards. Tampa Electric also supports the consideration of the following for NERC CIP standards: (1) Removal of data collection requirements (CIP-005-3a,-4a R5.3, CIP-006-3c,-4c R7 and R8.3, CIP-007-3,-4 R5.1.2, R6.4and R7.3, CIP-008-3,-4 R2); and (2) Removal of annual review requirements (CIP-002-3,-4 R4, CIP-003-3,-4 R1.3, R4.3, R5.1.2, and R5.3, CIP-006-3c,-4c R1.8, CIP-007-3,-4 R9, and CIP-009-3,-4 R1).

Response

There was much discussion around the PRC and CIP standards during the collaborative process. There are several issues that impact the retirement of these requirements including not creating a reporting gap by retiring PRC standards and the coordination of CIP standards with the Version 5 SDT. Given these complications, the P81 SDT believes it is best to consider these CIP and PRC Standards as part of a subsequent phase of the P81 project. To address Tampa Electric's other concern, the P81 SDT has been coordinating its activities with the CIP Version 5 SDT, and will continue to do so, so that the agreed upon retirements do not reemerge in CIP Version 5.

Comment

Occidental Power Services, Inc. requests the removal of the PSE function from the applicable sections of the following: INT-001-3 R1, INT-004-2 R2, IRO-001-1.1 R3, IRO-001-1.1 R8, IRO-005-3 R10, TOP-005-2 R3, and VAR-001 R5. ACES Power Marketing Standards Collaborators also suggests removing PSE and LSE the applicable sections of IRO-005-3 R10.

Response

The removal of applicable from the requirements is an interesting suggestion that would take some more technical review and modification of the requirements. Thus, the P81 SDT believes this suggestion is more appropriate for consideration in a subsequent phase of P81.

Comment

Georgia Transmission Corporation suggests the following additions: MOD-016-1.1 R1, MOD-016-1.1 R1.1, MOD-016-1.1 R3, MOD-017-0.1 R1, MOD-017-0.1 R1.1, MOD-017-0.1 R1.2, MOD-017-0.1 R1.3, MOD-017-0.1 R1.4, MOD-018-0 R1, MOD-018-0 R1.2, MOD-018-0 R1.3, MOD-018-0 R2, MOD-019-0.1 R1, MOD-020-0 R1, MOD-021-1 R1, MOD-021-1 R2, MOD-021-1 R3, PRC-005-1b R2, PRC-005-1b R2.1, PRC-005-1b R2.2, PRC-006-1 R7, PRC-006-1 R8, PRC-006-1 R14, PRC-007-0 R2, PRC-007-0 R3, PRC-011-0 R2, PRC-015-0 R3, PRC-017-0 R2, PRC-018-1 R5, PRC-021-1 R2, PRC-023-1 R3.3, and TOP-001-1a R4.

Response

Georgia Transmission Corporation points out many of the same requirements that the trade associations suggest for subsequent phases of the P81 project. As mentioned above, for example, we are deferring the consideration of MOD-004-1 to a subsequent phase so it may be considered in the context of other MOD Standards. The P81 SDT believes it is more appropriate to consider Georgia Transmission Corporation's suggestions in a subsequent phase.

Comment

South Carolina Electric and Gas asked if the measures associated with requirements being proposed for retirement would be modified or removed as well.

Response

The relevant measures and other associated elements will be marked as retired in the standard. These will be identified in the redlines of the standards that will be posted with the requirements during the next comment period.

Comment

ERCOT states that the justification statement for BAL-005-0.1b R2 could benefit from additional clarification regarding how it is redundant with BAL-001 R1 and R2 and the justification for EOP-009-2 R2 should also be enhanced.

Response

The P81 SDT notes that additional clarification for BAL-005-0.1b R2, EOP-009-0 R2 and other requirements will be included in the technical white paper being developed by the P81 SDT.

In summary, of the initial list in the draft SAR, MOD-004-1, VAR-002-WECC-1 R2 and VAR-501-WECC-1 R2 have been deferred to a subsequent phase. Of the suggested additions, it appears that only VAR-001-2 R5, FAC-010-2.1 R5 and FAC-011-2 R5 satisfy the P81 criteria without significant technical review, and, thus, are appropriate to be added to the final SAR for the initial phase. As a general note, any requirements suggested for the initial phase, but not adopted, shall be considered by the P81 SDT in a subsequent phase of the project, and, therefore, the entities do not need to resubmit the requirements.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	From page 25 of the SAR, "Since PRC-008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; PRC-010-0 R2; PRC-022-1 R2 provides little protection to the BES and better handled under event analysis and lessons learned papers, it should be removed." is not valid due to that fact that as of this posting the Event Analysis Program (EAP) has not become part of the RoP and is therefore a voluntary program. The requirements that are covered by these standards are mandatory cannot be replaced by a voluntary program. Refer to the following:Additionally, the EAP process is an after-the-fact Analysis of an event or events. These standard requirements (PRC-008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; PRC-010-0 R2; PRC-022-1 R2) address different needs which can be determined only if such an event occurs. For example, from PRC-008-0--"R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance." This requirement addresses the need to have an equipment maintenance and testing program in place prior to an event. Discovering that an entity did not have this as a result of an event analysis would, in this case, be after the damage is done and would not serve reliability. Analyzing why the UFSL program did not operate properly would come under the purview of the EAP but that is different from the Standard's intent. PRC-008-0--"R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days)." If the EAP was relied upon to meet this requirement the receipt or confirmation of this program would only occur after an event. PRC-009-0--"R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall

Organization	Yes or No	Question 2 Comment
		analyze and document its UFLS program performance in accordance with its Regional Reliability Organization’s UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:R1.1 A description of the event including initiating conditions.R1.2 A review of the UFLS set points and tripping times.R1.3 A simulation of the event.R1.4 A summary of the findings."Although this Standard appears that it could be covered under EAP, it is a highly detailed technical study and needs to be carried out on its own accord. Event Analysis will focus primarily what caused the event that triggered the UFLS program but not necessarily the program itself. Because of the importance of the UFLS program to the reliability of the system, its performance should not be analyzed only on a voluntary basis and not only by those entities that actually shed load as a result of the event, but against the whole regional program.PRC-009-0--”R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.”This is administrative, refer to the response for R1 preceding. PRC-010-0--”R2. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).” This should not triggered only after an event, see preceding response for R1 preceding. PRC-022-1--”R2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.”This is the same situation as for the UFLS program. Refer to the responses preceding. IRO-014-2 --The following requirements in Standard IRO-014-2 are administrative requirements only and do not enhance reliability, and should be considered for removal in the Initial

Organization	Yes or No	Question 2 Comment
		Phase. “R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: [Violation Risk Factor: Lower] [Time Horizon: Same Day Operations and Operations Planning]2.1. Review and update annually with no more that 15 months between reviews. 2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.”FAC-003-1 Requirements R3, and R4 (shown below) and their sub-requirements are administrative (reporting) requirements only and do not enhance reliability, and should be considered for removal in the Initial Phase. R3. The Transmission Owner shall report quarterly to its RRO, or the RRO’s designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.R4. The RRO shall report the outage information provided to it by Transmission Owner’s, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.In addition, as shown below, CIP-005-3 R4 and CIP-007-3 R8 are essentially the same. Suggest to eliminate CIP-005-3 R4 and include assessment of access points in CIP-007-3 R8.CIP-005-3 R4:"R4. Cyber Vulnerability Assessment - The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following: R4.1. A document identifying the vulnerability assessment process; R4.2. A review to verify that only ports and services required for operations at these access points are enabled; R4.3. The discovery of all access points to the Electronic Security Perimeter; R4.4. A review of controls for default accounts, passwords, and network management community strings; R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan." CIP-007-3 R8:"R8. Cyber Vulnerability Assessment - The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the

Organization	Yes or No	Question 2 Comment
		following: R8.1 A document identifying the vulnerability assessment process; R8.2 A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled; R8.3 A review of controls for default accounts; and, R8.4 Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan."
Southwest Power Pool Regional Entity	No	SPP RE does not agree that PRC-008 R1 and R2 should be retired or that they provide "little protection to the BES and [are] better handled under event analysis and lessons learned papers". UFLS equipment maintenance and testing programs ARE important to BES reliability, in a preventative mode, and are NOT covered under the Event Analysis process. Preventative maintenance is very important to reliability; without it, events are more likely. Industry should not wait for an event to happen to collect information and consider maintenance and testing. UFLS is the last line of "defense in depth protection of the BES" (Criteria C6). SPP RE's comment follows the discussion around removing PRC-005 and its relationship to BES reliability.SPP RE does not agree that CIP-007-3 R7.3 should be retired. R7.3 requires the Responsible Entity to maintain records of how data storage media was erased or destroyed prior to disposal or redeployment of the Cyber Asset (which could be simply the media previously removed from the Cyber Asset). In the absence of such records, the Responsible Entity cannot demonstrate compliance with CIP-007-3 R7.1 and CIP-007-3 R7.2, rendering those requirements not auditable. Elimination of this requirement could also result in a loss of visibility of Cyber Assets that have been disposed of or redeployed, also hampering the ability of the Responsible Entity to demonstrate compliance and the Compliance Enforcement Authority to audit compliance with the remaining requirements.
Bonneville Power Administration	No	BPA does not support the proposed retirement of TOP-001-1a R3. BPA does not agree that TOP-001-1a R3 is redundant with IRO-001-1a R8 because IRO-001-1a R8 only addresses RC directives, whereas TOP-001-1a R3 addresses both RC directives and TOP directives. BPA believes that retiring TOP-001-1a R3 before TOP-001-2 R1 is

Organization	Yes or No	Question 2 Comment
		effective would create a gap because no requirement would address TOP directives. BPA supports the additional proposed retirements and thanks the drafting team for their efforts.
ACES Power Marketing Standards Collaborators	No	(1) We believe there are other requirements that easily meet the criteria. (2) VAR-001-2 R5 is redundant with FERC's pro forma tariff and was originally included in the NERC policies to align them with said tariff. The requirement compels the PSE and LSE to arrange for reactive resources to satisfy the reactive requirements of the Transmission Service Provider. PSEs and LSEs cannot purchase transmission service without purchasing reactive service or demonstrating to the transmission provider that they have arranged for reactive resources. From a practical perspective, this means they always purchase reactive service from the Transmission Provider. Furthermore, it is the Transmission Operator that actually ensures reactive resources are dispatched per VAR-001-2 R2. Thus, VAR-001-2 R5 satisfies criteria B.1, B.6, B.7, and B.9.(3) BAL-002 R1 and R3 are redundant. R1 compels the BA to have access to and operate Contingency Reserve to respond to disturbances. R3 requires the BA to activate sufficient Contingency Reserve to comply with DCS. We suggest removing R1 because it is redundant (Criterion B.7). This applies to both versions 0 and 1 of the standard.(4) BAL-005-0.1b R1 and its sub-requirements are not necessary. All generation, transmission and load is currently contained within the metered boundaries of a BA. It is impossible to add new generation, transmission and load and not be within the metered boundaries of a BA. To do so, would require the equipment owner to carve out an area from the BA. For example, if a TO added a new transmission line, it would have to put a meter on both ends to carve it out of any BA footprint. In the process, they, in effect, create a new BA. The only way these requirements can't be met would be if BAs started removing metering equipment en masse. Given removing metering equipment has significant financial consequences due to inaccurate energy accounting; it is not going to happen. Thus, it meets Criterion B.9. Furthermore, TOs are already required to identify metering requirements in FAC-001-0 R2.1.6 as part of its facility connection requirements. It also meets Criterion B.7.(5) COM-001-1.1 is unnecessary and the audit of it has

Organization	Yes or No	Question 2 Comment
		largely become a demonstration that it is an administrative requirement. English is the primary language across the vast majority of the Interconnections under NERC's purview and it is the primary language in all of the areas under FERC's jurisdiction. For the few companies in areas where English is not predominant, those companies will be unable to meet other requirements if they use a different language to speak with companies from predominantly speaking English languages. Furthermore, audits have regulated this to predominantly an administrative requirement. The auditors largely look for statement that the English language is required despite the fact that all evidence has been provided in English, observations of control center conversations have shown English is used, and the audit has been conducted in English. If there is a need for this requirement, it should be relegated to a regional requirement for those regions that include areas that do not speak predominantly English. Thus, this requirement meets Criteria B.1 and B.9.(6) FAC-010-2.1 R5 is an administrative requirement for the Planning Authority to respond to comments on its SOL methodology. Failure to provide a written response to technical comments does not impact reliability. The PC is already required to distribute its methodology in R4. Any functional entity that would have provided technical comments will see any adjustments. This requirement meets Criteria B.1 and B.9.(7) FAC-011-2 R5 is an administrative requirement for the Reliability Coordinator to respond to comments on its SOL methodology. Failure to provide a written response to technical comments does not impact reliability. The RC is already required to distribute its methodology in R4. Any functional entity that would have provided technical comments will see any adjustments when they receive the methodology. This requirement meets criteria B.1 and B.9.(8) INT-004-2 R1 has nothing to do with reliability and should be included in the list of retirements. Failing to reload an Interchange Transaction that was curtailed for a reliability event has no reliability impact. It is a remnant from the NERC Policies that was added at the request of market participants because once transactions were cut, reliability entities did not always allow the transaction to resume once the reliability issue had been addressed. This is strictly a commercial issue. Thus, this requirement meets Criterion B.9.(9)

Organization	Yes or No	Question 2 Comment
		IRO-005-3 R10 should be modified to reflect the functional model. In cases where there are differences in derived limits, PSEs and LSE cannot operate to the most limiting parameters. They are not in a position to even have information on the parameters such as facility ratings. Rather, their role is to follow directives. Thus, inclusion of PSE and LSE in the requirement does not support reliability. Thus, this requirement meets Criterion B.9. (10) IRO-005-3 R11 is redundant with MOD-028-1 R6.1, MOD-029-1a R3, and MOD-030-2 R2.4. The MOD standards already require the TSP to consider IROLs and SOLs when determining Available Transfer Capability/Available Flowgate Capability and Total Transfer Capability. This requirement meets Criterion B.7. (11) PRC-011-0 R2 should be retired. A requirement is not needed to compel the TO and DP to provide data on its UVLS equipment maintenance program to the Regional Entity. The Regional Entity's CMEP and NERC's Rules of Procedure compel the TO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(12) PRC-015-0 R3 should be retired. A requirement is not needed to compel the TO, GO and DP to provide data on their Special Protection Systems (SPS) to the Regional Entity. The Regional Entity's CMEP and NERC's Rules of Procedure compel the TO, GO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(13) PRC-016-0.1 R3 should be retired. A requirement is not needed to compel the TO, GO and DP to provide data on their SPS Misoperations analyses and corrective action plans to the Regional Entity. The Regional Entity's CMEP and NERC's Rules of Procedure compel the TO, GO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(14) PRC-017-0.1 R2 should be retired. A requirement is not needed to compel the TO, GO and DP to provide documentation of the SPS maintenance and testing program to the Regional Entity. The Regional Entities CMEP and NERC's Rules of Procedure compel the TO, GO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(15) PRC-

Organization	Yes or No	Question 2 Comment
		021-0.1 R2 should be retired. A requirement is not needed to compel the TO and DP to provide UVLS program data to the Regional Entity. The Regional Entities CMEP and NERC's Rules of Procedure compel the TO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(16) PRC-023-1 R2 and PRC-023-2 R3 are redundant with FAC-008-1 R1.2.1 and FAC-008-3 Part 2.4.1. FAC-008-1 R1.2.1 and FAC-008-3 Part 2.4.1 already require the GO and TO to consider relay protective devices when determining facility ratings. The DP cannot limit the Facility Rating because a DP does not have Transmission Facilities. They only have relays that impact Facility Ratings that must ultimately be considered by the TO. This requirement meets Criterion B.7(17) TOP-005-2a R3 is redundant with the INT standards and should be retired. In the NERC Functional Model, the only role for the PSE is to facilitate Arranged Interchange. The INT standards already govern Arranged Interchange and contain the necessary information that the PSE must provide. Furthermore, Project 2007-03 Real-Time Operations has proposed retirement of this requirement as it is redundant with NAESB e-Tag specifications. Beyond the E-tag data there is no additional information that a PSE or LSE could provide for the BA or TOP to conduct operational assessments. This requirement meets Criteria B.6, B.7 and B.9.(18) PRC-006-1 R7 should be retired. Failure by a Planning Coordinator to provide data to another Planning Coordinator within 30 days is not a reliability issue because Planning Assessments have long time lines to complete the studies. Furthermore, any failure to provide data within 30 calendar days is most likely a simple oversight. If a Planning Coordinator refuses to provide data, the requesting Planning Coordinator may get involved and which will compel them to provide the data. This can be done without the need for this requirement. This requirement meets criterion B.4.
Western Electricity Coordinating Council	No	WECC supports the majority of the Standards Requirements identified, but notes concerns with the following. WECC recommends eliminating CIP-003 R1 in its entirety.WECC disagrees with the inclustion of CIP-007, R7.3. This requirement is necessary for entity's to demonstrate compliance with the other sub-requirements of CIP 007 R7. However, this requirement could be moved to a Measure or RSAW to

Organization	Yes or No	Question 2 Comment
		demonstrate compliance with the other sub-requirements of CIP-007, R7.WECC disagrees with the includsion of IRO-016-1, R2. Required documentation of the RC's actions to remedy an event is necessary for quality and efficient root cause analysis, including insight into the RC's wide view of actions during an event or disagreement. The language in the SAR statement for IRO-016-1 R2 points to this information being monitored through Spot Checks or other compliance monitoring methods. If this standard is removed yet the information is to be included in future compliance monitoring there must be some sort of methodology that requires the entity to retain the associated data to be kept for the duration of the required cycle for monitoring (i.e. audit cycle if monitored through audits). It is important that entities document the actions taken that analyze the effect on the system as well as the BES for either an even or/and for the disagreement on the problem. Therefore, it is important that this information is part of the overall compliance monitoring program.MOD-004 is not redundant to TOP-002 even though the CBM itself may be a tariff issue and rarely used. The reliability piece is that if the CBM is used by a TSP then the details of it must be available for use in system studies. Without the awareness of a transmission holdback for CBM when it exists, a network study could be run and show no issues but if at some time the CBM were implemented an overload could result. This might not always be the case but unless the CBM parameters are known and modeled it could impact reliability.WECC disagrees with the recommendations with PRC-008-0 R1 and PRC-008-0 R2. Unless these standards are being superseded, WECC does not agree that they provide "little protection to the BES." They are not administrative in nature like the other standards in this group. They insure that maintenance and testing program is established and implemented for an entity's UFLS protection systems. Without these standards, there is reduced assurance that UFLS protection systems will operate correctly when called upon for an under-frequency event. UFLS has a vital role in its effectiveness for preserving system stability and elimination of these standards may reduce its effectiveness. This standard is about making sure the equipment is maintained not about collecting data. If and when PRC-005-2 is adopted, and if it were to include the UFLS devices, then this standard should be

Organization	Yes or No	Question 2 Comment
		considered for removal.WECC believes the statements associated with TOP-001-1a, R3 are incorrect. Removing TOP-001-1a would result in no NERC requirement for parties to follow TOP directives. The current TOP-001-1a R3 requires BOTH TOP and RC directives to be followed. The proposed IRO-001-3 R2 requires ONLY RC directives to be followed. In addition, the SAR statement is incorrect. TOP-001-1a R3 applies to directives issued by the TOP (and also the RC). IRO-001-1a applies only to directives from the RC. If the intent, as they state, is to replace TOP-001-1a R3 with IRO-001-3, that leaves a void for an entity to comply with a directive from the TOP. Only the part about following an RC directive is redundant. Requirement should be modified to eliminate the redundancy, but not retired. WECC disagrees witht he inclusion of CIP-001, R4. An entity has many enforcement agencies to contact without the FBI listed in the operating instructions they could easily be overlooked. This Requirement has encouraged entities to establish a current communication line with the FBI. In fact, several other larger entities are members of InfraGardÂ®, which is a partnership between the FBI and the private sector. Retiring R4 will remove the incentive of having a working relationship with the FBI, especially among the smaller entities. Retiring R4 may effectively delay or prevent the FBI from rapidly locating those responsible for sabotage. The requirement is not “needlessly burdensome”, which is a criteria for deletion.WECC believes the requirements VAR-002-WECC-1, R2, and VAR-502-WECC-1, R2, are probably the best way of demonstrating compliance with the accociated R1 requirments. The two VAR R2 requirements do not say the entity has to submit the information to WECC (Regional Entity), only that it shall have the documentation to prove exclusion for the sub requirements in R1. We’ve had cases where entities don’t meet the 98% availability and if the entity was claiming exclusion time, WECC would want to review the documentation that proves the exclusion. It is in the entity’s best interest to keep exclusion documentation in case its units don’t make the 98%, but this is beter suited for a Measure or RSAW.
Independent Electricity System Operator	No	(1) We generally agree that most of the identified standards/requirements would meet the proposed criteria. However, as indicated under Q1, we believe that the “annual review” criterion is too broad which could result in retiring some

Organization	Yes or No	Question 2 Comment
		requirements that are still needed for reliability. In addition, the acid test for retirement a requirement is when the standard drafting team reviews the overall reliability impact of removing a particular requirement from a standard, and how it may affect other related standards. In brief, it is premature to pass on this judgment at the SAR stage. We urge the SAR proponent to simply suggest that the proposed requirements be considered and evaluated by the SDT as opposed to making a presumption (and hence setting a high expectation for the industry) that the proposed list will be retired. And, in order to meet the requirements for regulatory approval, we suggest the SDT to provide strong technical basis to justify each retirement.
American Electric Power	No	AEP does not disagree with a majority of the requirements proposed by the drafting team, though we recommend the team reconsider the inclusion of CIP-003 R3 and associated sub-requirements. AEP recommends instead that CIP-003 R1 be removed in which case CIP-003 R3 (and CIP-003 R2.4) can also be removed. However, if the drafting team does not agree with this recommendation, CIP-003 R3 must be retained in order for entities to take targeted exception(s) where applicable (for example, in circumstances where an entity’s program is more stringent than the CIP requirements).AEP would like the team to consider the following additional Reliability Standard requirements as candidates for retirement on this initial, or subsequent, request for comment. Standard: PRC-021-1Requirement: R2Requirement Text: Each Transmission Operator and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.Criterion: B4,9Standard: PRC-018-1Requirement: R5Requirement Text: The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.Criterion: B2Standard: PRC-016-0.1Requirement: R3Requirement Text: The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).Criterion: B4Standard: PRC-015-0Requirement:

Organization	Yes or No	Question 2 Comment
		R3Requirement Text: The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).Criterion: B4Standard: PRC-011-0Requirement: R2Requirement Text: The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).Criterion: B4Standard: PRC-007-0Requirement: R3Requirement Text: The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).Criterion: B4Standard: CIP-006Requirement: R1.5Requirement Text: Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.Criterion: B7Standard: CIP-007Requirement: R5.1.1Requirement Text: The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.Criterion: B7Standard: CIP-007Requirement: R5.1.3Requirement Text: The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.Criterion: B7Standard: CIP-007Requirement: R6.3Requirement Text: The Responsible Entity shall maintain logs of system events related to cyber security, where technically Feasible, to support incident response as required in Standard CIP-008-3.Criterion: B7Standard: CIP-007Requirement: R6.4Requirement Text: The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.Criterion: B1, B3Standard: CIP-003-3, CIP-003-4Requirement: R1Requirement Text: Cyber Security Policy - The Responsible Entity shall document and implement a cyber security policy that represents

Organization	Yes or No	Question 2 Comment
		management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:Criterion: B1, B3, B7, B9Standard: CIP-003-3, CIP-003-4Requirement: R1.2Requirement Text: The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets. Criterion: B1, B3, B7, B9Standard: CIP-003-3, CIP-003-4Requirement: R1.3Requirement Text: Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2. Criterion: B5Standard: CIP-003-3, CIP-003-4Requirement: R2.4Requirement Text: The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy. Criterion: B7Comment: Although AEP does not necessarily agree with removal of this requirement (see R3 comment below), R2.4 is redundant with R3.3 (which is being removed) and should probably be removed along with R3.Standard: CIP-003-3, CIP-003-4Requirement: R3 (R3.1, R3.2, R3.3)Requirement Text: Exceptions - Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s). Criterion: Comment: If R1 is not removed, R3 (or some exception process) is necessary. For example, if the Cyber Security Policy goes above and beyond the standards, then an exception may be needed even though the standards are met.
Public Service Enterprise Group	No	For these requirements, KEEP:CIP-001-2a R4. If the entity owns or operates a BES asset, there is a clear reliability benefit to have appropriate law enforcement contacts and procedures to address sabotage or other security incidents. Similarly, the federal agencies feel that this is a good idea. In a coordinated attack environment, sabotage reporting to these Law enforcement agencies from the BES operators and owners would improve the ability of a coordinated response. Thus we feel that this requirement should be kept within the standards.CIP-003-3 R3. The exceptions language in R3, though rarely used, allows for those instances where an entity is unable to conform with it's cyber security policy. In addition, the requirement has been approved by the industry and FERC more than once. It's removal may have a negative impact on the industry. CIP-003-4 R3. The exceptions language in R3, though

Organization	Yes or No	Question 2 Comment
		rarely used, allows for those instances where an entity is unable to conform with it's cyber security policy. In addition, the requirement has been approved by the industry and FERC more than once. It's removal may have a negative impact on the industry. TOP-005-2a R1. "TOP-003-2 requires operating entities such as GOs and TOs to provide operating data to BAs ands TOPs. In TOP-005-2a, R2 and R3 requires BAs and TOPs to exchange this data with other BAs and TOPs . R1 requires BA and TOP recipients of such data to execute a confidentiality agreement so that its confidentiality is protected. This requirement ultimately protects the confidentiality of data provided by entities under TOP-003-2.For these requirements, KEEP BUT MODIFY:FAC-002-1 R2. We believe the three year limitation on documentation sets a limit; otherwise six years may be required (the period between audits. We do suggest removing the language " and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days)." because we see no reliability benefit.For these rerquirements, KEEP UNTIL REPLACED:EOP-004-1 R1. NERC's Event Analysis Process was approved by NERC's BOT on February 9, 2012. This process has already been adopted as RFC's process under EOP-004-1, R1. Draft standard EOP-004-2 will replace Regional reporting requirements in R1 with consistent NERC-wide requirements; however, while the draft does not presently require the use of the NERC Event Analysis Process, that process is embedded in proposed NERC ROP changes filed with FERC on May 7, 2012. Keep until these NERC ROP changes are approved by FERC and become effective.PRC-008-0 R1. This is required for reliability. Such a testing program has been incorporated into draft PRC-005-2 When this is adopted, PRC-008-0 can be retired.PRC-009-0 R1. The NERC Event Analysis Process is embedded in proposed NERC ROP changes filed with FERC on May 7, 2012. Keep until these NERC ROP changes are approved by FERC and become effective.PRC-009-0 R1.1. See R1 above.PRC-009-0 R1.2. See R1 above.PRC-009-0 R1.3. See R1 above.PRC-009-0 R1.4. See R1 above.
Essential Power, LLC	No	CIP-001-2a, R4. This requirement should be removed from the Paragraph 81 project. If an entity owns or operates a BES asset, there is a clear reliability benefit to have

Organization	Yes or No	Question 2 Comment
		appropriate law enforcement contacts and procedures to address sabotage or other security incidents. Similarly, the federal agencies feel that this is a good idea. In a coordinated attack environment, sabotage reporting to these law enforcement agencies from the BES operators and owners would improve the ability of a coordinated response. Thus we feel that this requirement should be kept within the standards.CIP-003-3, R3. This requirement should be removed from the Paragraph 81 project. The exceptions language in R3, though rarely used, allows for those instances where an entity is unable to conform to its cyber security policy. In addition, the requirement has been approved by the industry and FERC more than once. Its removal may have a negative impact on the industry.CIP-003-4, R3. This requirement should be removed from the Paragraph 81 project. The exceptions language in R3, though rarely used, allows for those instances where an entity is unable to conform to its cyber security policy. In addition, the requirement has been approved by the industry and FERC more than once. Its removal may have a negative impact on the industry.EOP-004-1, R1. This requirement should be removed from Phase 1 of the Paragraph 81 project, until replaced by EOP-004-2. NERC's Event Analysis Process was approved by NERC's BOT on February 9, 2012. This process has already been adopted as RFC's process under EOP-004-1, R1. Draft standard EOP-004-2 will replace Regional reporting requirements in R1 with consistent NERC-wide requirements; however, while the draft does not presently require the use of the NERC Event Analysis Process, which is embedded in proposed NERC ROP changes filed with FERC on May 7, 2012. This requirement should be kept until these NERC ROP changes are approved by FERC.FAC-002-1, R2. This requirement should be removed from the Paragraph 81 project, and modified instead. We believe the three year limitation on documentation sets a limit; otherwise six years may be required (the period between audits). We do suggest removing the language “and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days)." because we see no reliability benefit to this element of the requirement.
Occidental Power Services,	No	OPSI recommends the following additions for Phase 1 implementation: 1. INT-001-3, R1. The Load Serving, Purchasing-Selling Entity shall ensure that Arranged

Organization	Yes or No	Question 2 Comment
Inc.		Interchange is submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.Criteria: B6, B9Statement: This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses.Recommendation: Remove PSE from R1 and from the Applicability section.2. INT-004-2, R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:o R2.1 The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than Â±10%o R2.2 The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than Â±25 megawatt-hourso R2.3 A Reliability coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons. Criteria: B6,B9Statement: This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses.Recommendation: Remove PSE from R2 and from the Applicability section.3. IRO-001-1.1, R3 and R8.R3. The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing- Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.R8. Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the

Organization	Yes or No	Question 2 Comment
		Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.Criteria: B9Statement: PSEs do not generally receive Reliability Directives from RCsRecommendation: Remove PSE from R3 and R8 and from the Applicability section.4. IRO-005-3, R10. In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.Criteria: B9Statement: PSEs do not generally derive limits for the transmission of power over the BES.Recommendation: Remove PSE from R10 and from the Applicability section.5. TOP-005-2, R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.Criteria: B6,B9Statement: PSEs have to supply this information as a requirement for participating in market functions.Recommendation: Remove PSE from R3 and from the Applicability section.6. VAR-001, R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.Criteria: B6,B9Statement: This is a requirement to participate in competitive markets (generally, it is included in the transmission rate) or is required by tariffs in non-competitive markets. The PSE has no option but to purchase the reactive power in order to make the transaction.Recommendation: Remove PSE from R5 and from the Applicability section.
Georgia Transmission Corporation	No	GTC agrees that the suggested list easily satisfies the criteria in the draft SAR, but GTC also believes this is an incomplete list for Phase I. GTC also believes the following Reliability Standard requirements easily satisfy the criteria listed in the draft SAR and recommends reconsidering and adding to the list in the initial Phase I.MOD-016-1.1;R1:The Planning Authority and Regional Reliability Organization shall have

Organization	Yes or No	Question 2 Comment
		documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses. [Meets Criteria A, B1, B2, B3, B9]MOD-016-1.1 R1.1 The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values. Meets Criteria A, B1, B3, B4, B9MOD-016-1.1 R3 The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area. Meets Criteria A, B1, B3, B9MOD-016-1.1 R3.1 The Planning Authority shall make this distribution within 30 calendar days of approval. Meets Criteria A, B1, B3, B9MOD-017-0.1 R1 The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-1_R1. Meets Criteria A, B1, B4, B9MOD-017-0.1 R1.1 Integrated hourly demands in megawatts (MW) for the prior year. Meets Criteria A, B1, B4, B9MOD-017-0.1 R1.2 Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. Meets Criteria A, B1, B4, B9MOD-017-0.1 R1.3 Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years. Meets Criteria A, B1, B4, B9MOD-017-0.1 R1.4 Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested. Meets Criteria A, B1, B4, B9MOD-018-0 R1 The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or

Organization	Yes or No	Question 2 Comment
		dispersed basis) shall: Meets Criteria A, B1, B3, B9MOD-018-0 R1.1 Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and Meets Criteria A, B1, B3, B9MOD-018-0 R1.2 Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load. Meets Criteria A, B1, B3, B9MOD-018-0 R1.3 Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-1_R 1. Meets Criteria A, B1, B3, B9MOD-018-0 R2. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days). Meets Criteria A, B1, B4, B9MOD-019-0.1 R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-1_R 1. Meets Criteria A, B1, B4, B9MOD-020-0 R1. The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days. Meets Criteria A, B1, B4, B9MOD-021-1 R1. The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed. Meets Criteria A, B1, B3, B9MOD-021-1 R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy

Organization	Yes or No	Question 2 Comment
		for Load in the data reporting procedures of Standard MOD-016-0_R1. Meets Criteria A, B1, B3, B9MOD-021-1 R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days). Meets Criteria A, B1, B3, B9PRC-005-1b R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include: Meets Criteria A, B1, B3, B9PRC-005-1b R2.1. Evidence Protection System devices were maintained and tested within the defined intervals. Meets Criteria A, B1, B3, B9PRC-005-1b R2.2. Date each Protection System device was last tested/maintained. Meets Criteria A, B1, B3, B9PRC-006-1 R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. Meets Criteria A, B1, B4, B9PRC-006-1 R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. Meets Criteria A, B1, B4, B9PRC-006-1 R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following:14.1. UFLS program, including a schedule for implementation 14.2. UFLS design assessment 14.3. Format and schedule of UFLS data submittal Meets Criteria A, B1, B3, B9PRC-007-0 R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a

Organization	Yes or No	Question 2 Comment
		UFLSprogram database. Meets Criteria A, B1, B4, B9PRC-007-0 R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days). Meets Criteria A, B1, B3, B4, B9PRC-011-0 R2. The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days). Meets Criteria A, B1, B3, B4, B9PRC-015-0 R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days). Meets Criteria A, B1, B4, B9PRC-017-0 R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days). Meets Criteria A, B1, B3, B4, B9PRC-018-1 R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years. Meets Criteria A, B1, B2, B3, B9PRC-021-1 R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request. Meets Criteria A, B1, B4, B9PRC-023-1 R3.3. The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list. Meets Criteria A, B1, B4, B9TOP-001-1a R4. Each Distribution Provider and Load-Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory

Organization	Yes or No	Question 2 Comment
		requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions. Same requirement as R3 which made the Phase I list, only difference is applicability.
NERC Staff Technical Review	No	After further review, NERC Staff recommends that the SDT review the following standard requirements and consider moving them from Phase I to Phase II. If the SDT determines the following standard requirements still fall into Phase I, a more robust technical justification would be needed.(1) FAC-008-1 R2, R3, FAC-008-3 R4, R5 and FAC-013-2 R3: These requirements, combined with others, provide checks and balances on the Facility Rating Methodology and Transfer Capability methodology established by the responsible entities. This provides a reliability benefit by requiring the responsible entity to consider areas in which their methodology may not be sufficient to support reliable operation of the interconnected transmission system. There may be better ways of assuring that entities have sufficient methodologies and alternatives should be considered during Phase II. NERC Staff suggests that the SDT reconsider whether discussing the methodology (and not the numerical rating of a facility) has commercial or market related implications. With respect to FAC-013-2 R3, NERC Staff suggests that the SDT reconsider whether the requirement relates to "a back and forward on transfer capability" as noted in the draft SAR, as the requirement pertains only to the methodology for determining transfer capability.(2) PRC-008-0 R2: Maintenance and testing of underfrequency load shedding (UFLS) relays is necessary to assure reliable operation of a UFLS program and this requirement is included in PRC-005-2 as part of Project 2007-17, Protection System Maintenance and Testing. NERC Staff recommends that the language in R2 relating to implementing its UFLS equipment maintenance and testing program remain to avoid a reliability gap prior to the effective date of PRC-005-2. NERC Staff recognizes that the second part of R2 does meet the criteria in the SAR and recommends that the SDT consider revising the requirement in a future phase to remove the language that requires an entity to "provide UFLS maintenance and testing program results to

Organization	Yes or No	Question 2 Comment
		its Regional Reliability Organization and NERC on request (within 30 calendar days).” (3) TOP-001-1a R3: The technical justification states that this requirement is redundant with IRO-001-1a R8. NERC Staff notes that the requirement is only partially redundant until IRO-001-3 is approved by FERC and therefore, it is premature to consider it for Phase I; it should be considered for Phase II.(4) MOD-004-1: NERC Staff notes that there are a number of Commission directives associated with MOD-004-1 and the technical justification provided for the elimination of this standard should directly address these directives. If a solid technical justification cannot be made, NERC Staff suggests that the requirements should not be included in Phase I. In addition to the above, NERC Staff recommends that the SDT consider removing the following standard requirements from the scope of the P81 project:(1) PRC-008-0 R1: The requirement to have a maintenance and testing program for UFLS is necessary to assure reliable operation of a UFLS program and this requirement is included in PRC-005-2 as part of Project 2007-17, Protection System Maintenance and Testing. NERC Staff recommends retaining R1 to avoid a reliability gap prior to the effective date of PRC-005-2.(2) PRC-009-0 R1: Analysis to assess the performance of UFLS equipment and program effectiveness following system events provides a reliability benefit by identifying whether the UFLS program is effective and whether modifications are necessary. A requirement similar to R1 is included in FERC-approved standard PRC-006-1 and NERC Staff recommends retaining R1 to avoid a reliability gap prior to the effective date of PRC-006-1. If the SDT believes this requirement is not necessary, the justification for removing R1 should discuss Commission comments in Order No. 763 pertaining to Requirement R11 in PRC-006-1.(3) VAR-002-WECC-1 and VAR-501-WECC-1: NERC Staff notes that the regional standards should be removed from the scope of the P81 project because they must first be eliminated via the regional standards development process prior to being processed through the NERC standard development process.
MidAmerican Energy Company	No	FERC Order 706 clearly states that an exception forms alternative obligations for the responsible entity to meet the requirements; an exception is not an exemption from the requirements. We believe a Responsible Entity should still be allowed to have

Organization	Yes or No	Question 2 Comment
		exceptions to its cyber security policy. MidAmerican Energy Company agrees with the proposed removal of CIP-003-3 (CIP-003-4) R3, R3.1, R3.2, R3.3, as long as CIP-003-3 (CIP-003-4) R2.4 remains and allows for possible exceptions to a Responsible Entities' cyber security policy. R2.4 states "The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy." When removing requirements eligible for TFEs, revisions to the Rules of Procedure Appendix 4D - Procedures for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards will be necessary. For example, CIP-005-3, R2.6 should be deleted from the list of requirements with TFEs in the Scope section on page 1 if the requirement is removed as part of this process.
SPP Standards Review Group	Yes	From our review of the list we feel that this is again, a good starting point, but would hope that the drafting team could add or subtract requirements as needed as Phase 1 of the project develops.
The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA) (collectively, the Trade Associations).	Yes	The Trade Associations agree with the suggested list of Reliability Standard requirements contained in the SAR for the Initial Phase of P81.

Organization	Yes or No	Question 2 Comment
Salt River Project	Yes	Yes
SRC	Yes	o PRC-009-0 R1 - R2 are in the process of being retired by PRC-006-1 as such these requirements will eventually go away. o VAR-002-WECC-1 R2 - Regional standards/requirements for retirement should go through the regional standards process not the NERC continent wide process. o VAR-501-WECC-1 R2 - Regional standards/requirements for retirement should go through the regional standards process not the NERC continent wide process. o Consider adding IRO-014-2 R2 requirements: R2 Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: [Violation Risk Factor: Lower] [Time Horizon: Same Day Operations and Operations Planning]2.1. Review and update annually with no more that 15 months between reviews. 2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.These meet criteria B1 and B5.
Georgia System Operations Corporation	Yes	Georgia System Operations agrees with the suggested list of Reliability Standard requirements contained in the SAR for the Initial Phase of P81.
seattle city light	Yes	Seattle City Light supports the consolidated comments of the industry Trade Organizations.
Duke Energy	Yes	The initial phase of the P81 project should contain only requirements that can quickly gain industry and regulatory support and that there is adequate time to prepare a strong technical justification for. Duke Energy asks the P81 Standards Drafting Team to ensure these parameters are taken into consideration as the list is finalized, and move to a subsequent phase any requirements that could take additional time to develop a strong technical justification and consensus for.

Organization	Yes or No	Question 2 Comment
NV Energy	Yes	Our review of the rationale for each of the suggested requirements of the draft SAR supports the conclusion that these requirements should be subject to retirement.
Occidental Energy Ventures Corp.	Yes	OEVC believes that the phased approach proposed in the SAR is prudent and likely the most effective. Only the most obvious candidates for retirement or modification should be presented at this early date. If the industry moves too-far, too-fast, the result may be a blanket rejection of every proposal. Once FERC is comfortable that the industry is in-tune to their sense of risk - which includes public perception of their oversight effectiveness - we believe they will be prepared to deal with requirements that seem important on the surface, but whose contribution to reliability is illusory.
South Carolina Electric and Gas	Yes	Will the measures associated with requirements that are up for retirement be modified or removed?Eg. Removing R2 of a standard but not removing the text in M1 which refers to R2 of that same standard.
Ameren	Yes	We appreciate the excellent work done by the P81 Project team in developing the criteria and agree with the list of suggested standards/requirements that easily satisfy the criteria in this initial phase.
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the ISO/RTO SCR comments. However, in addition to the SRC comments, ERCOT offers the following:ERCOT agrees that all the requirements included in the SAR warrant retirement based on the relevant criteria, as supported by the corresponding justification statements. ERCOT offers the following additional comments related to the justification statements for the SDT's consideration:BAL-005-0.1b R2 - The justification statement could benefit from additional clarification regarding the reason why this requirement is redundant, because it isn't readily apparent why this is redundant with BAL-001 R1 and R2. Maintaining CPS requires the use of regulation. Therefore, it is implicit that the relevant functional entities have regulation to comply with BAL-001 R1 and 2. Also, the justification should clarify the point of the discussion related to equating compliance based on

Organization	Yes or No	Question 2 Comment
		compliance of BAL-001 R 1 and 2 and how that argument justifies retirement. CIP-001-2a R4 - The justification statement should clarify that this requirement is redundant to the communications obligations in R1-3.CIP-003-3, 4 R1.2 - In addition to the justifications presented in the SAR, the term “readily available” is ambiguous and creates the opportunity for the use of CEA subjective judgment during compliance assessments. This is problematic for compliance risk generally, but is especially problematic when the requirement is administrative in nature. Entities should not be subject to unnecessary compliance risk based on ambiguity that can result in subjective compliance determinations based on the opinion of CEA personnel, as opposed to the four corners of the requirements, especially when the underlying requirement provides no reliability value. Further evidence that this requirement serves no purpose is the fact that it is not included in CIP v5. CIP-003-3 R3, 3.1, 3.2 and 3.3 - In addition to the justifications presented in the SAR, this issue is already fully addressed in the TFE process in Appendix 4D of the ROP, which is not only adequate, but is the appropriate place for this type of administrative function related to documentation. There are a specific set of defined requirements that allow an exception, and those exceptions have be to be filed according to the TFE process. Thus, the requirements proposed for retirement are redundant to that process. CIP-003-3, -4 R4.2 - In addition to the justification presented in the SAR, the phrase “based on sensitivity”, is ambiguous and creates the opportunity to insert subjective judgment into compliance assessments. This is problematic for compliance risk generally, but especially when the requirement is administrative in nature AND redundant. Entities should not be subject to unnecessary compliance risk based on ambiguity resulting in subjective compliance determinations, as opposed to the four corners of the requirements, especially when the underlying requirement provides no operational reliability value. Further evidence that this requirement serves no purpose is the fact that it is not included in CIP v5. CIP-005-3a, -4a R2.6 - The justification statement could benefit from additional clarification as to why the banner is not useful. An appropriate use banner has not been useful over time, because people who intend to use sites inappropriately will simply ignore the

Organization	Yes or No	Question 2 Comment
		banner. Banners are generally considered to be a legal protection and not a security protection. Further evidence that this requirement serves no purpose is the fact that it has been removed from CIP v5 because the use of banners does not meet a reliability objective.CIP-007-3, -4 R7.3 - In addition to the justification presented in the SAR, it should be noted that to demonstrate that an entity performed the data destruction under R7.1 and R7.2, the entity needs to collect evidence. Having a separate requirement for evidence is redundant and not needed. COM-001-1.1 R6 - In addition to the justification presented in the SAR, the justification statement could note that this policy should be documented in the ROP for information within NERCNet that is considered sensitive or impacting to the BES. It should be a voluntary best practice or business practice for other information so that entities may use it, or use some other policy that better fits its circumstances. The justification should state that the NERCNet policy should be a voluntary best practice type of issue for information that is not considered sensitive or impacting to the BES. EOP-009-0 R2 - This is a reporting obligation and a documentation issue. The justification statement should also note that both documentation and reporting on this does not rise to the level of a reliability standard. The statement could note that this may be a best practices issue, but just for documentation. Reporting test results to REs isn't a best practice. Additionally, the justification should not state that the relevant information is better considered / obtained during an audit. If it's not relevant to the mandatory requirements, then it has no place in CMEP proceedings.FAC-002-1 R2 - The justification should not include that the relevant information is better considered / obtained during an audit. If it's not relevant to the mandatory requirements, then it has no place in CMEP proceedings.FAC-008-1 R1.3.5 - In addition to the justification presented in the SAR, the justification statement could note that the term "other assumptions" is ambiguous and introduces the potential for inefficient/ineffective administration of the CMEP due to introduction of subjectivity and opinions into compliance assessments. This is problematic for compliance risk generally, but especially when the requirement is administrative in nature AND redundant. Entities should not be subject to unnecessary compliance risk based on ambiguity resulting in

Organization	Yes or No	Question 2 Comment
		subjective compliance determinations, as opposed to the four corners of the requirements, especially when the underlying requirement provides no operational reliability value.FAC-008-1 R2; FAC-008-1 R3; FAC-008-3 R4; FAC-008-3 R5 - In addition to the justification presented in the SAR, the justification statement could note that it is inappropriate for entities other than the owners of equipment to establish facility ratings. The owners don't have to change their ratings, but the scheme is far more effective if the respective functional roles are distinct and not blurred by the review process contemplated in the requirements proposed for retirement. The owners should set the ratings and the RCs receive them and perform their functions in accordance with those ratings. The RC should not be involved with the TO/GO business-management of their equipment. Also, by keeping the roles distinct, it mitigates any liability risk of the third party if the owner uses its input and then the equipment breaks because of the new rating;FAC-013-2 R3 - Same comment as above.MOD-004-1 R1; MOD-004-1 R1.1; MOD-004-1 R1.2; MOD-004-1 R1.3; MOD-004-1 R2; MOD-004-1 R3; MOD-004-1 R3.1; MOD-004-1 R3.2; MOD-004-1 R4; MOD-004-1 R4.1; MOD-004-1 R4.2; MOD-004-1 R5; MOD-004-1 R5.1; MOD-004-1 R5.2; MOD-004-1 R6; MOD-004-1 R6.1; MOD-004-1 R6.2; MOD-004-1 R7; MOD-004-1 R8; MOD-004-1 R9; MOD-004-1 R9.1; MOD-004-1 R9.2; MOD-004-1 R10; MOD-004-1 R11; MOD-004-1 R12; MOD-004-1 R12.1; MOD-004-1 R12.2; MOD-004-1 R12.3 - ERCOT agrees with the comments/justifications.PRC-008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; PRC-010-0 R2; PRC-022-1 R2 - In addition to the justification presented in the SAR, the justification statement could note that the tasks required in these standards are administrative/documentation/reporting in nature and they don't affect reliability from a standards perspective. These could either be best practices or evidentiary in RSAWs - e.g. provide UFLS/UVLS program documentation - which could be relative to requirements that have actionable UVLS/UFLS requirements;TOP-001-1a R3 - ERCOT agrees with the justification with regard to the RC function, but the TOP standard also requires BAs/GOPs to follow the directives of the TOP, so the two relevant requirements are not apples to apples. Modification to one or the other

Organization	Yes or No	Question 2 Comment
		may be needed to ensure appropriate authority and corresponding obligation to follow that authority is reflected in one or the other standard, or both, but eliminate overlaps.TOP-005-2a R1 - ERCOT agrees with the justification. This should either be in the ROP or just via the ISN access process/agreement.VAR-002-WECC-1 R2; VAR-501-WECC-1 R2 - ERCOT agrees with the justification, but if the documentation/reporting are not relevant for the requirement, then the SAR should not suggest the REs should seek the info in CMEP proceedings, which should solely focus on compliance with the substance of the standards.
SERC EC Planning Standards Subcommittee	Yes	
Dominion	Yes	
Pepco Holdings Inc & Affiliates	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Tampa Electric Company	Yes	
Manitoba Hydro	Yes	
City of Garland	Yes	
Entergy Services, Inc.	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Central Husdon Gas & Electric	Yes	

Organization	Yes or No	Question 2 Comment
Corporation		
Tucson Electric Power	Yes	
CPS Energy	Yes	
Edison Mission Marketing & Trading	Yes	
Illinois Municipal Electric Agency	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Transmission Agency of Northern California	Yes	
Kansas City Power & Light	Yes	

3. **The subsequent phases of the P81 project are designed to identify all FERC-approved Reliability Standard requirements that could not be included in the Initial Phase due to the need for additional analysis or an editing of language. Please list any Reliability Standard requirements that you believe should be revised or retired in a subsequent phase, and include a brief supporting statement and citation to at least one element of Criterion B for each requirement listed.**

Summary Consideration:

The P81 SDT is very appreciative of the time and effort the commenters spent developing their responses to Question 3. The commenters proposed numerous requirements for consideration in a subsequent phase, including requirements in BAL, CIP, INT, FAC, MOD, and PRC Reliability Standards, among others. As a general observation, the commenters suggested several ways to handle Reliability Standard requirements in the subsequent phases, including (i) retiring a requirement; (ii) modifying the requirement; (iii) changing the functional applicability of a requirement; and (iv) combining requirements or standards. Also, several commenters, such as ERCOT, Independent Electricity System Operator and SPP Standards Review Group requested the ability to raise additional Reliability Standard requirements during the subsequent phases. Given the level of interest in the subsequent phases of the P81 project, it is appropriate for the P81 SDT to carefully consider how best to propose a process for the subsequent phases. To some extent, ERCOT said it well:

"The SDT should establish a prospective process that provides adequate time and opportunity for entities to perform a meaningful review of remaining requirements to determine which additional requirements warrant retirement and to develop appropriate criteria, if relevant, that may be incremental to the ones proposed in this SAR, and to develop appropriate retirement justifications based on the relevant retirement criteria."

Consequently, while all the requests for consideration of Reliability Standard requirements in subsequent phases will receive consideration (including those requirements suggested for Phase I, but deferred to a subsequent phase), the process by which that consideration will be undertaken needs to be developed in light of the requirements suggested for subsequent phases. Accordingly, based on the comments, the P81 SDT intends to develop and suggest options to the Standards Committee in the near future on how to move forward with the subsequent phases.

Organization	Yes or No	Question 3 Comment
ACES Power Marketing		(1) EOP-002-3 R6 and R7 and their sub-requirements are redundant with BAL-001-

Organization	Yes or No	Question 3 Comment
Standards Collaborators		0.1a R1 and R2 and BAL-002 R4. BAL-001-0.1a R1 compels a BA to meet CPS1. BAL-001-0.1a R2 compels a BA to meet CPS2. BAL-002 R4 compels a BA to respond meet the DCS for all reportable events less than MSSC. EOP-002-3 R6 and R7 do not make the BA any more or less responsible to meet these requirements but rather creates an opportunity for double jeopardy. Furthermore, EOP-002-3 R6 and R7 do not make any sense in context with the CPS1 and CPS2 calculations. They are averages over a long term and would never require the emergency actions listed in the sub-requirements to comply with them. These requirements have already proven to incent behavior that is contrary to reliability (criterion B.8). At the August NERC BOT meeting, the NERC OC Chair explained that a BA shed load to meet the DCS criterion even though there were no other concerns (i.e. voltage, frequency, IROL or SOL violations) on the transmission system at the time. These requirements meet criterion B.7. (2) EOP-004-1 R2 should be considered for future retirement. The approval of the Event Analysis Procedure obviates the need for a standard requirement to analyze Bulk Electric System disturbances. This would be especially true if the procedure is added to the Rules of Procedure as NERC has planned. This requirement meets criterion B.7.(3) Retirement of FAC-001-0 R3 should be considered in the next phase. There is an implied obligation for the TO to update its Facility connection requirements when they change. Additionally, a requirement to make them available to the Regional Entity and users of the transmission system is unnecessary. First, the Regional Entity could request them through the compliance monitoring process. Second, the TO will provide the Facility connection requirements to those with genuine interconnection requests because the TO will want its connection standards met. This requirement meets criterion B.4, B.7 and B.9. (4) FAC-002-1 R1 should be revised to reflect the NERC Functional Model because it assigns the requirements to the wrong functional entities. The Transmission Planner and Planning Coordinator are responsible for conducting the assessments for new Facilities. The requirement appears to be an attempt to require the GO, TO, DP, and LSE to coordinate with the TP and PC. However, the requirement actually defines what is required in the TP and PC assessments which unfortunately place these

Organization	Yes or No	Question 3 Comment
		responsibilities on the GO, TO, DP and LSE. None of these functional entities have the capability to meet requirements such as performing dynamics studies. This requirement meets criterion B.8. (5) VAR-001-2 R2 and TOP-006-2 R2 are duplicate requirements. VAR-001-2 R2 compels the TOP to acquire sufficient reactive resources. TOP-006-2 R2 requires the RC, TOP and BA to monitor reactive resources. Since VAR-001-2 R2 applies all the time, a TOP cannot know they have acquired and maintained reactive resources unless they are monitoring them. Furthermore, TOP-006-2 R2 incorrectly applies to the BA. According to the NERC Functional Model, the BA cannot monitor reactive resources that are not generators and have no role in ensuring system voltages. Thus, TOP-006-2 R2 meets criterion B.7 because it is redundant, and it meets criteria B.8 and B.9 because it assigns responsibility to a functional entity (BA) that cannot meet it. This distracts the BA from its reliability mission.
Independent Electricity System Operator		(1) IRO-004-2 R1 could be retired if the wording in IRO-001-1.1 R8 was changed to cover all operating timeframes (Criterion B7). (2) We do not have any other particular standards/requirements in mind at this time. However, we will review and propose additional candidates for future phases as this project gets into the mid or end of Phase I. We believe the industry should focus on the Phase I effort at this time to gauge the regulator's and industry's reaction before marching too far down the path.
Western Electricity Coordinating Council		CIP 002 R2/R3/R4: Redundant and require revision. Each of these requirements requires an annual review of the Critical Asset list and Critical Cyber Asset list. WECC agrees these protections are required, however, the standard should be revised so either CIP 002-3 R4 is removed and CIP 002-3 R1-R3 are revised to require annual review and approval of the appropriate documentation, or CIP 002-3 R2 and R3 are revised to no longer require an annual review.CIP 005 R1.5/006 R3: These are redundant and should be removed/revised. CIP 006-3 R3 is redundant with CIP 005-3 R1.5. Either CIP 005-3 R1.5 should be revised to no longer require the protections of CIP 006-3 R3, or CIP 006-3 R3 should be removed and the content of CIP 006 R3 moved to CIP 005 R1.5.CIP 005 R1.5/006 R2.2: Redundant. Should be revised. Devices

Organization	Yes or No	Question 3 Comment
		applicable to these requirements may be redundant if they are classified as CCA (thus duplicated with CIP 002 - CIP 009) or reside within an ESP (thus duplicated with CIP 007). The requirements should be revised to take into account the situation where a device resides within an ESP or is classified as CCA, and is a device used in the EACM/PACM of ESPs/PSPs. Note: It appears this is being addressed in V.5 of CIP.CIP-005, R5: Should be removed and the protections highlighted in this requirement moved to appropriate requirements it references. This will cause less confusion with entities, and be more precise with exactly what documentation is required to be reviewed and approved.CIP 005 R5.1/R5.2: Redundant. Should revise CIP 005 R1.6 to include the wording of CIP 005 R5.1, and remove CIP 005 R5.1. This will cause less confusion with entities, and be better aligned with the CIP 005 R1.6 requirement.CIP 005 R5.3: Redundant. Should revise CIP 005 R3 to include the wording of this sub-requirement, and CIP 005 R5.3 should be removed. This change will create a better fit in the appropriate requirement, and be less confusing for entities.CIP 007 R9: Should be removed and the protections highlighted in this requirement moved to appropriate requirements it references. Thus CIP 007 requirements that require documentation should include the need to review and update the documentation. This will cause less confusion with entities, and be more precise with what documentation is required to be reviewed and approved.EOP-004-1 R3.2: Little, if any, value as a reliability requirement. This requirement points to attachments that could be addressed in the main part of the R3 standard. This requirement does nothing to promote the protection of the BES.VAR-001-2 R10: Redundant. The reliability purpose for R10 is to make sure that operators don’t think that exceeding an SOL or IROL due to voltage issues is acceptable. There are multiple standards requiring operators not exceed and maintain an SOL or IROL with 30 minutes, regardless of the cause of the exceedance. These standards are TOP-001-2 R7, R11; TOP-004-2 R1; TOP-007-0 R2; TOP-008-1 R1.
Entergy Services, Inc.		CIP-006 R5 - A revision to the language in CIP-006 R5 is needed in order to require the review and handling of incidents of unauthorized access (when a door, gate or window has been opened without authorization), as opposed to what is more

Organization	Yes or No	Question 3 Comment
		accurately characterized as "unsuccessful" access attempts (e.g. invalid access card swipes). There currently is no definition of "unauthorized access attempts". The methods to be used for monitoring that are listed in the requirement, however do list: "Alarm Systems that alarm to indicate a door, gate or window has been opened without authorization". This method does not indicate that the alarm system must alarm on card swipes that do not result in the door opening, and be characterized as "Unauthorized Access attempts". Unsuccessful card swipes at a PSP access point, for example, do not suggest an unauthorized access attempt. A card swipe can be unsuccessful for a number of reasons, all of which are recorded by the key card system, such as the use of a deactivated card, an invalid card format, and a card not in the card file. An unsuccessful card swipe itself is not an indication that a PSP access point was “opened within authorization” because it does not indicate that the door has been opened in any manner. However, in the FAQ guidance for the CIP Reliability Standards, NERC acknowledged that Responsible Entities can consider single failed access attempts such as a single failed log-in not to be suspicious events requiring a response A single failed card swipe should be treated in the same way. The rewording of this requirement would address Criteria B-8 - "Hinders the protection or reliable operation of the BES." Investigating and documenting each unsuccessful card swipe would take a tremendous amount of time and produce a significant amount of paperwork without providing any additional physical security.CIP-005 R3 and CIP-006 R5 - Revisions to the wording around the timing of monitoring both physical and electronic access are needed. CIP-005 R3 - Monitoring Electronic Access states that "The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week." and CIP-006 R5 -Monitoring Physical Access stats that "The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in

Organization	Yes or No	Question 3 Comment
		Requirement CIP-008-3.The "twenty-four hours a day, seven days a week" portion of these requirements provides an unachievable requirement for 100% uptime for all systems used to monitor such access. The requirement should allow for a resonable amount of downtime. Either the "twenty-four hours a day, seven days a week" wording in these requirements could be removed altogether, or alternative langauge, such as requiring "High Availability" (for example 99.9% uptime) or some other wording that allowed for very small amounts of downtime that might be required for system reboots or minor maintenance.
SRC		Consider including the following standards for review in Phase II:BAL-004-0 - Time Error CorrectionMOD-030-2 - Flowgate MethodologyPRC-006-1 R8 (provision of data)PRC-006-1 R14 (administrative - response to written comments)
MidAmerican Energy Company		Consider the list provided by EEI.
Georgia System Operations Corporation		EOP-002-3, R1PER-001-0.1, R1Criteria B7, 9Statement: reference to BA or RC responsibilities and authority are within the criteria of NERC's Functional Model and so this is redundant. In addition, it is understood that these functions are substantial if not paramount for an entity to become certified as such. FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: The requirement in FAC-001-0 to document and publish facility connection requirements has no impact on reliability. It is purely a document that those considering to interconnect with a transmission entity may review as a reference. All INT standardsCriteria B 1, 3 and 6Statement: Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Note: INT-007-1 R1.2 is part of Initial Phase. All data collection requirementsCIP-005-3a, 4a R5.3CIP-006c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4; R7.3CIP-008-3, -4 R2PRC-018-1, R5Criteria B1,2 and 9Statement: These requirements are for data retention and although the need is

Organization	Yes or No	Question 3 Comment
		substancial, i.e. as a sort of forensic tool, they serve no function to reliability from an immediate time perspective.Standards currently requiring reporting.Criteria 1, 4 and 9EOP-002-3 R9.2EOP-004-1 R3 and its subrequirements; R4 and R5FAC-003-1 R3; FAC-003-1 R3.1: FAC-003-1 R3.2: FAC-003-1 R3.3: FAC-003-1 R3.4: FAC-003-1 R3.4.1: FAC-003-1 R3.4.2: FAC-003-1 R3.4.3: FAC-003-1 R4FAC-010-2.1 R5FAC-011-2 R5FAC-013-2 R6MOD-012-0 R2MOD-020-0 R1MOD-021-1 R3PRC-004-1a R3: PRC-004-2a R3: PRC-004-WECC-1 R.3.PRC-007-0 R2; PRC-007-0 R3; PRC-009-0 R2 PRC-011-0 R2; PRC-015-0 R3; PRC-016-0.1 R3; PRC-017-0 R2; PRC-021-1 R2TPL-001-0.1 R3; TPL-002-0b R3; TPL-003-0a R3; TPL-004-0 R2.Statement: These are all reporting requirements; they do not aid reliability from an immediate time perspective. If the Regional Entity desires to review information for purposes of monitoring reliability or assessing risk, the information should be collected via vehicles other than the Reliability Standards.Requirements applied to annual reviewsCriteria B1, 2,3 7 and 9CIP-002-2, -4 R4CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4 R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4 R9CIP-009-3, -4 R1EOP-005-1 R1; EOP-005-2 R3.1EOP-008-0 R1.7EOP-008-1 R5IRO-014-1 R4.3Statement: These requirements do not closely relate to operations of the Bulk Electric System. They would be better served as processes expected of entities to manage their compliance programs and processes. PRC-005-1b, R2Criteria B4, 9Statement: This requirement needs to be revised such that language is elminated as it refers to the entity providing to its RE within 30 days. MOD-016-1.1 and MOD-021-1 (all requirements) Criteria B 9Statement: MOD-016 through MOD-021 are all about long term load forecasting and reporting of actual loads. Most of this can be eliminated from the standards and replaced with a data collection process (e.g., DADS). Loads to be used in modeling should be incorporated in the data requirements of MOD-010 and MOD-012 and not a separate standard.
Electric Reliability Council of Texas, Inc.		ERCOT agrees with the ISO/RTO SCR comments. However, in addition to the SRC comments, ERCOT offers the following:ERCOT supports future phases of the P81 project to eliminate/retire reliability standards that do not facilitate BES reliability. ERCOT is reviewing all standards to that end, however, developing a list of additional

Organization	Yes or No	Question 3 Comment
		requirements for retirement will require additional time. The SDT should establish a prospective process that provides adequate time and opportunity for entities to perform a meaningful review of remaining requirements to determine which additional requirements warrant retirement and to develop appropriate criteria, if relevant, that may be incremental to the ones proposed in this SAR, and to develop appropriate retirement justifications based on the relevant retirement criteria.
City of Austin dba Austin Energy		FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: The requirement in FAC-001-0 to document and publish facility connection requirements has no impact on reliability. It is purely a document that those considering to interconnect with a transmission entity may review as a reference. Once an interconnection request is actually made with a transmission owner, the transmission owner performs the FAC-002-1 steady-state, short-circuit, and dynamics studies to determine the new interconnection's impact on reliability. During the negotiation of an interconnection agreement the FAC-001-0 referenced material is agreed on and reduced to writing for purposes of constructing, maintaining and operating the interconnection facilities. Also, during the entire interconnection process, as FAC-002-1 provides for, the parties must coordinate and cooperate during the assessment of the reliability impact of the new interconnection facilities. Thus, FAC-001-0, at best, is a best practice or helpful initial guide to an entity considering interconnecting, but provides little, if any, meaningful value to reliability, especially when compared to the actual benefits to reliability via the FAC-002-1 studies, the execution of a negotiated agreement and the coordination of activities during constriction and operation of the new facilities. Accordingly, FAC-001-0 should be retired, and, if necessary, any requirements that protect reliability should be transferred to FAC-002-1. All INT Standards Criteria B 6, 7 and 9Statement: Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, we recommend that the Standards Drafting Team retire the INT Reliability Standards and, as necessary, transfer any requirement that protect

Organization	Yes or No	Question 3 Comment
		reliability to the BAL Reliability Standards. All data collection requirements not included in the Initial Phase, more specifically:CIP-005-3a, -4a R5.3CIP-006c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4CIP-008-3, -4 R2PRC-018-1 R5Criteria B 1, 2 and 9Statement: These requirements are purely data retention requirements with no functional nexus to reliability and, therefore, best handled via compliance monitoring, RSAW or as a data request during an audit. All reporting out requirements not included in the Initial Phase, more specifically:EOP-002-3 R9.2EOP-004-1 R3 and its subrequirements; R4 and R5FAC-003-1 R3; FAC-003-1 R3.1: FAC-003-1 R3.2: FAC-003-1 R3.3: FAC-003-1 R3.4: FAC-003-1 R3.4.1: FAC-003-1 R3.4.2: FAC-003-1 R3.4.3: FAC-003-1 R4FAC-010-2.1 R5FAC-011-2 R5FAC-013-2 R6MOD-012-0 R2MOD-020-0 R1MOD-021-1 R3PRC-004-1a R3: PRC-004-2a R3: PRC-004-WECC-1 R.3.PRC-007-0 R2; PRC-007-0 R3; PRC-009-0 R2 PRC-011-0 R2; PRC-015-0 R3; PRC-016-0.1 R3; PRC-017-0 R2; PRC-021-1 R2TPL-001-0.1 R3; TPL-002-0b R3; TPL-003-0a R3; TPL-004-0 R2.Criteria B 1, 4 and 9Statement: There is no direct connection between reporting out of information to an entity or Regional Entity and protecting reliability. If the Regional Entity desires to review information for purposes of monitoring reliability or assessing risk, the information should be collected via vehicles other than the Reliability Standards.Annual reviewsCIP-002-3, R3; CIP-002 -4 R3CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4 R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4 R9CIP-009-3, -4 R1EOP-005-1 R1; EOP-005-2 R3.1EOP-008-0 R1.7EOP-008-1 R5IRO-014-1 R4.3Criteria B 1, 2, 3, 7 and 9Statement: The annual review and update requirements are arbitrary, administrative and not aligned with the operation and protection of the Bulk Electric System. These requirements should be retired or modified to align with how the Bulk Electric System is operated and protected. Other requirementsCIP-007-3, -4 R7 Criteria B 1, 2, 3 and 7Statement: The essential elements of the process of disposing or redeploying of Cyber Assets and the associated cyber security are set forth in R7.2 and R7.3. To require "formal methods, processes and procedures" appears to require formal documentation for the sake of documentation, rather than allowing the responsible entity to implement a process that achieves the actions required in R7.2 and R7.3,

Organization	Yes or No	Question 3 Comment
		which may or may not include formal procedures, for example. EOP-004-1 R2Criteria B 7 Statement: The analysis of the BES for system disturbances is covered in PRC-004-2.1a R1. The PRC Requirement R1 calls for the analysis of its transmission Protection System Misoperations. We believe that BES analysis is covered inherently through this PRC standard making EOP-004 R1 redundant to the PRC standard.Another factor is the Version 2 of the EOP-004-2 where the requirement to analyze the BES disturbance is noticeably absent. The focus on the EOP-004 is for the reporting of applicable events that are identified in the PRC-004 standard. There is an event analysis reporting process referenced in the NERC Rules of Procedures (ROPs) that handles this requirement. Therefore, this is a redundant requirement. In February of 2012, NERC deployed its Events Analysis Process - incorporating the learnings from two field trials held over the previous year and a half. It includes all the necessary steps that affected operators must take to analyze and report on events that may impair the reliability of the BES. Most Regional Entities have already updated their reporting procedures to match NERC's. Furthermore, NERC and the Regional Entities already have sufficient authority to order analyses and corrective action plans outside of the Reliability Standards. These are important steps for the development of Lessons Learned and trending analyses, but do not contribute to reliable operations. In fact, the demand for near term reporting - some within one hour of the initiation of the event - interferes with the efforts of front-line personnel to mitigate the issue at handBAL-001-0.1a (all requirements), BAL-004-0 (all requirements), BAL-005-0.1b R11; BAL-006-2 (all requirements)Criteria B 6 and 9Statement: BAL-001 requires a 12 month rolling average of ACE and does not impact reliability and should be eliminated (in favor of BAL-002). Consider augmenting NAESB standard WEQ-005.BAL-004 requirement for time error correction is not important for reliability and should be eliminated. It also duplicates NAESB std WEQ-006.In BAL-005 R11, Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE, is not needed for reliability. Ramp rates have minimal impact on ACE calculations, and are already included in the

Organization	Yes or No	Question 3 Comment
		definition of Interchange Schedule in the NERC Glossary as used in R9. The requirement to use agreed upon ramp rates is commercial in nature and is already covered by NAESB standard WEQ-004-17.BAL-006-2 is an after-the-fact accounting of inadvertent interchange and does not impact reliability and should be eliminated. Consider augmenting NAESB standard WEQ-007.CIP-003-3, -4 R2 and its subrequirementsCriteria B 1 and 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether there is an employee called a CIP senior manager oversees the plan. CIP-004-3, -4 R2.3 Criteria B 9Statement: Whether the entity has a robust up-to-date, trained-on CIP compliance plan may impact reliability, but not whether there is annual training. CIP-004-3, -4 R3.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether there is a seven year update to the PRA. CIP-004-3, -4 R4.1Criteria B 1, 9Statement: Whether the entity has a robust up-to-date on CIP compliance plan may impact reliability, but not whether it reviews lists every seven days. CIP-004-3, -4 R4.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date on CIP compliance plan may impact reliability, but not whether it revokes access within 24 hours or 7 days. CIP-005-3a, -4a R2.5 and its subrequirementsCriteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan to protect the ESP may impact reliability, but not whether specific information is documented. CIP-007-3, -4 R3.1, R3.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan to protect the PSP may impact reliability, but not whether specific information is documented within 30 days. Also, whether the entity has a robust up-to-date on CIP compliance plan to protect the PSP may impact reliability, but not whether specific information is documented. CIP-008-3 R1.4Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether specific information is documented within 30 days or a change. EOP-001-1b, -2bCriteria B 7Statement: Duplicative with the other EOP Standards (e.g., Capacity and Energy emergency of EOP-002, Load Shedding of EOP-003, and System Restoration of EOP-005).EOP-002-3 R1Criteria B 7Statement: Duplicates other

Organization	Yes or No	Question 3 Comment
		requirements such as IRO-001-1 R8 and should be retired or modified to reduce redundancy. EOP-002-3 R9 Criteria B 7Statement: When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources). It duplicates NAESB standard WEQ-008 and should be eliminated.EOP-005-2 R1.2.A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration. Criteria B 1, 3 and 7 Statement: With the implementation of NUC-001-2 R2, there is no longer a need for EOP-005-2 R1.2. Specifically, NUC-001-2 R2 requires Nuclear Plant Interface Requirements (NPIRs) to be included in the agreements for operation and maintenance (including restoration process) for off-site nuclear power:R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements1 that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.Given the off-site power requirements of NUC-001-2 which require comprehensive operational interface protocols (including restoration) between nuclear plants and responsible entities as part of the NPIRs, there is no longer a need for the administrative, documentation-only requirement in EOP-005-2 related to the same subject matter.IRO-002-2 (all requirements)Criteria B 7Statement: Redundant with COM-002-2, R1 COM-001-1.1, R1 and IRO-002-2, R2 and R3IRO-005-3a R10Criteria B 9Statement: Confusing requirement. It was intended to address rare cases where entities were told to operate to different SOLs and IROLs. However, because only the TOP and the RC can see these parameters, the only thing a GOP can do is follow a directive.IRO-014-1 R4Criteria B 9Statement: Requirement 4 (including sub-parts) should be rolled up into R1. and eliminated. Requirement 1 should be modified to require "current operating procedures, processes or plans with all adjacent RCs.IRO-015-1 R2.1Criteria B1 and 9Statement: Whether the procedure, process and plan is

Organization	Yes or No	Question 3 Comment
		robust and up-to-date may impact reliability, not whether there are weekly calls.MOD-001-1 and MOD-008-1 (all requirements)Criteria 6 and 9Statement: Do the ATC / TTC standards belong in NERC or NAESB (i.e., MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12)? I think NERC should be focused on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc., and I think these can/should be moved to the NAESB standards.Criteria B 6 and 9Statement: This could be handled as a data request from an RE or other Registered Entities and, therefore, would not need a requirement, as there are too many requirements that warrant an attestation that no request was made.MOD-016-1.1 and MOD-021-1 (all requirements) Criteria B 9Statement: MOD-016 through MOD-021 are all about long term load forecasting and reporting of actual loads. Most of this can be eliminated from the standards and replaced with a data collection process (e.g., DADS). Loads to be used in modeling should be incorporated in the data requirements of MOD-010 and MOD-012 and not a separate standard.MOD-028-1 (all requirements); MOD-029-1a (all requirements); MOD-030-2 (all requirements)Criteria B 6 and 9Statements: ATC / TTC standards should belong NAESB (i.e., MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12)? NERC should focus on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc.PRC-022-1 R1, R1.1, R1.2, R1.3, R1.4, and R1.5Criteria B 7Statement: Whether the responsible entity has robust UVLS misoperation and correction action is redundant with PRC-004-1a, -2a. TOP-001-1a R3 and R7 (and its subrequirements)Criteria B 9Statement: For R3, there are three projects in progress addressing the issuance of directives by the RC, BA and TOP. Also, for R7, all outages information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-002-2b R8 and R 9Criteria B 6, 7 and 9Statement: “Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency”, duplicates VAR-001 and should be eliminated. “Each Balancing Authority shall plan to meet Interchange Schedules and ramps” duplicates the BAL standards and the NEASB standards and should be eliminated.TOP-002-2b R12Criteria B 6 and 9Statement: ATC / TTC standards should belong to NAESB (i.e., MOD-001, MOD-004, MOD-008,

Organization	Yes or No	Question 3 Comment
		MOD-028 thru 030, and TOP-002-2 R12). NERC should focus on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc., These can/should be moved to the NAESB standard.TOP-002-2b R14 and R14.1Criteria B 9Statement: All derating information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-002-2b R15Criteria B 9Statement: Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations is a "how" requirement that is needed to meet other requirements in the standard. It is also not measureable, and the requirement should be eliminated. All weekly forecasts should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-003-1 R1 and its subrequirements; R2 and R3Criteria B 9Statement: All planned outage information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-005-2a R3Criteria B 9Statement: PSEs are not best positioned to provide reliability information.BAL-005-0.1b R1Criteria B7Statement: Introductory statement; redundant with subrequirements MOD-010-0 R2Criteria B 1, 4 and 9Statement: MOD-012-0 R2 was included in the Joint Trade Associations list of suggested requirements for retirement or modification. MOD-010-0 R2 is nearly identical to MOD-012-0 R2 and should also be considered.PER-001-0.1 R1Criteria B7Statement: The TOP portion of this requirement is redundant with TOP-001-1a R1PRC-018-1 R3 (and all sub requirements)Criteria B2 and 4Statement: This requirement involves data collecting and reporting that does not impact the reliability of the BES; could be part of a data request if necessary
Georgia Transmission Corporation		FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: The requirement in FAC-001-0 to document and publish facility connection requirements has no impact on reliability. It is purely a document that those considering to interconnect with a transmission entity may review as a reference. MOD-016-1.1 and MOD-021-1 (all requirements) Criteria Meets Criteria A and a combination of either or all of B1, B2, B3, B4, B 9Statement: MOD-016 through MOD-021 are about long term load forecasting and reporting of actual and forecast loads. Requirements could be eliminated from the standards and replaced with a data collection process (e.g.,

Organization	Yes or No	Question 3 Comment
		TADS/DADS, etc.). Loads to be used in modeling could be incorporated in the data requirements of MOD-010 and MOD-012 and not a separate standard. Additionally, MODs-016 through 021 have yet to be classified as Tier 1, 2, or 3; nor have they yet to be identified on NERC's Actively Monitored List.PRC-006-1 (R7, R8, and R14) Criteria: Meets Criteria A and a combination of either or all of B1, B3, B4, B9Statement: Recommend these requirements to be eliminated from the standards and replaced with a data collection and or reporting process (e.g., TADS/DADS, etc.). PRC-023-1 (R3.3) Criteria: Meets Criteria A and a combination of either or all of B1, B4, B9Statement: Recommend these requirements to be eliminated from the standards and replaced with a data reporting process.TOP-001-1a (R4) Criteria: Meets Criteria A and B1Statement: Same requirement as TOP-001-1a (R3) which made the Phase I list, only difference is applicability.
Occidental Power Services, Inc.		If the changes listed in Question 2 are not considered in Phase 1, then they should be considered in subsequent phases of the project.
Illinois Municipal Electric Agency		IRO-010-1a R3
Idaho Power Company		MOD-017-0.1 R1.1, R1.2 Criterion B2MOD-018-0 R1 Criterion B7 (Should be covered by MOD-016)MOD-021-1 R1, R2 Criterion B7 (Should be covered by MOD-016)MOD-021-1 R3 Criterion B4
CPS Energy		No additional comments.
Salt River Project		No additions at this time.
Occidental Energy Ventures Corp.		OEVC agrees with the process that the Trades are using to approach this question, but do not agree with some of their priorities. OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be

Organization	Yes or No	Question 3 Comment
		removed:a) BAL-005, R1.1 - BA metering is financial in nature. Telemetry is already required for reliability.b) TOP-002, R13 - Generator validations are driven by the regions already.FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: OEVC agrees with the Trade's analysis, but will also point out that once connection requirements are in place, they will rarely change. We believe this would mean a lower priority is in order. All INT Standards Criteria B 6, 7 and 9 Statement: Again, OEVC agrees with the Trades on this. It may even be time to suggest that the functional designation of the PSE go away. They serve a marketing purpose and are blind to reliability indicators. All data collection requirements not included in the Initial PhaseCIP-005-3a, -4a R5.3CIP-006c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4; R7.3CIP-008-3, -4 R2PRC-018-1 R5Criteria B 1, 2 and 9 Statement: OEVC agrees with the Trades. Most of these are captured in Phase I. These fit in the same category. All reporting out requirements not included in the Initial PhaseCIP-001-2a R3 should be modified to eliminate the word "reporting" (added by OEVC)EOP-002-3 R9.2EOP-004-1 R3 and its sub requirements; R4 and R5 FAC-003-1 R3; FAC-003-1 R3.1: FAC-003-1 R3.2: FAC-003-1 R3.3: FAC-003-1 R3.4: FAC-003-1 R3.4.1: FAC-003-1 R3.4.2: FAC-003-1 R3.4.3: FAC-003-1 R4FAC-010-2.1 R5FAC-011-2 R5FAC-013-2 R6MOD-010-0 R2 Similar to MOD-012-0 (added by OEVC)MOD-012-0 R2MOD-020-0 R1MOD-021-1 R3PRC-004-1a R3: PRC-004-2a R3: PRC-004-WECC-1 R.3.PRC-007-0 R2; PRC-007-0 R3; PRC-009-0 R2 PRC-011-0 R2; PRC-015-0 R3; PRC-016-0.1 R3; PRC-017-0 R2; PRC-021-1 R2TPL-001-0.1 R3; TPL-002-0b R3; TPL-003-0a R3; TPL-004-0 R2.Criteria B 1, 4 and 9 Statement: In addition to the Trade's comments, OEVC believes that NERC has an Events Analysis process, RAPA process, and Section 1600 Data Request process that they can invoke to get this information.Annual reviewsCIP-002-2, -4 R4CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4 R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4 R9CIP-009-3, -4 R1EOP-005-1 R1; EOP-005-2 R3.1EOP-008-0 R1.7EOP-008-1 R5IRO-014-1 R4.3Criteria B 1, 2, 3, 7 and 9 Statement: OEVC agrees with the Trades and add that Compliance teams spend far too much time trying to confirm that a RBAM was reviewed and signed off-on. This serves only to add time and expense - especially when conditions have not changed in the preceding year.

Organization	Yes or No	Question 3 Comment
		Other requirements EOP-004-1 R2 Criteria B 7 Statement: OEVC agrees with the Trades. Again, NERC has an Events Analysis process and RAPA process that they can invoke to require analyses. FAC-002-1 R1OEVC agrees that this requirement and five sub-requirements are unnecessary. First of all, the PUC, the BA, and the TOP are highly involved in the interconnection process. It is not clear what extra value is provided by overlapping oversight from the RE and/or NERC. Second, other standards - the TPLs in particular - are directly referenced in the requirement. Those are enforceable already, there is no need to duplicate them here.FAC-008-1 R1.3.5This requirement is already addressed in Phase I.IRO-001-1.1 R8 OEVC believes the intent is to consolidate RC directives in IRO-001 with TOP directives in TOP-001. Since Phase I addresses TOP-001, this seems to have been already accomplished.IRO-005-3a R10Criteria B 9Statement: OEVC agrees with the Trades. This is one that we propose should be a much higher priority. Since the GOP is already told to follow a directive, this requirement makes no sense. MOD-017-0.1 R1.1 and MOD-018-0 (all requirements) ; MOD-020-1 R1OEVC believes that this is redundant with IRO-010 and the new version of TOP-003 when it takes effect.MOD-019-0.1 R1OEVC believes that this is redundant with IRO-010 and the new version of TOP-003 when it takes effect. TOP-002-2b R2; R15OEVC believes that TOP-002 R15 will be resolved by the release of the new TOP standards.TOP-002-2b R14 and R14.1Criteria B 9Statement: OEVC believes that TOP-002 R14 and R14.1 will be resolved by the release of the new TOP standards.TOP-003-1 R1 and its sub requirements; R2 and R3Criteria B 9Statement: OEVC believes that these items will be resolved by the release of the new TOP standards.TOP-005-2a R3Criteria B 9Statement: OEVC agrees with the Trades on this one. Again, it may even be time to suggest that the functional designation of the PSE go away. TOP-006-2 R1.1, R4, R5, R6; TOP-008-1 R2, R4 OEVC believes that that TOP-006 R1.1 will be resolved by the release of the new TOP standards.
NERC Staff Technical Review		Please see NERC Staff's response to question 2 for Phase I requirements that NERC Staff recommends be reviewed for inclusion in a future phase. NERC Staff may propose additional requirements for a future phase of the P81 project at a later date.

Organization	Yes or No	Question 3 Comment
American Electric Power		Please see the response to Question #2 for additional Reliability Standard requirements that AEP would like to be considered as candidates for retirement on this initial, or subsequent, request for comment.
seattle city light		Seattle City Light supports the consolidated comments of the industry Trade Organizations.
Tampa Electric Company		Tampa Electric suggests that the P81 Drafting Team consider the adoption of concepts from the CIP version 5 criteria for consideration under CIP version 3 and 4. In particular Tampa Electric proposes that draft language for CIP-007 patching will reduce administrative burden for compliance with patching process TFEs under current versions (CIP-007 V3 and V4). The version 5 draft Guidelines and Technical Basis for CIP-007 V5 states: R2.1 A patch source is not required for Cyber Assets that have no updateable software or firmware (there is no user accessible way to update the internal software or firmware executing on the Cyber Asset), or those Cyber Assets that have no existing source of patches such as vendors that no longer exist. R2.2 Determination that a security related patch, hotfix, and/or update poses too great a risk to install on a system or is not applicable due to the system configuration should not require a TFE.
Manitoba Hydro		The following statement should be removed from the standard as it does not support reliability of the BES [B8]:FAC-013-2 R5. ‘However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request’The following statement should be removed from the standard as it does not support reliability or provide any protection to the BES. [B8]:FAC-013-2 R6. ‘If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to

Organization	Yes or No	Question 3 Comment
		that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information'.
The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA) (collectively, the Trade Associations).		The Trade Associations support the following list of Reliability Standard requirements to be retired or modified in a subsequent phase of the P81 project. To assist the Standards Drafting Team decide what should be considered in phase 2, phase 3 etc., the Trade Associations have listed the requirements in the order of importance - with those at the top of the list candidates for phase 2. The Trade Associations understand, however, that the decision on how best to proceed with phase 2, phase 3 will be weighed by the Standards Drafting Team, and, therefore, have not indicated any bright line on what should or should not be included in phase 2 versus phase 3, etc. The Trade Associations further note that the list of requirements listed below may be supplemented with additional requirements as the phase 2/phase 3 discussions evolve. Additionally, the Trade Associations believe that additional criteria for elimination may be proposed as part of the phase 2/phase 3 process.FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: The requirement in FAC-001-0 to document and publish facility connection requirements has no impact on reliability. It is purely a document that those considering to interconnect with a transmission entity may review as a reference. Once an interconnection request is actually submitted to a transmission owner, the transmission owner performs the FAC-002-1 steady-state, short-circuit, and dynamics studies to determine the new interconnection's impact on reliability. During the negotiation of an interconnection agreement the FAC-001-0 reference material is agreed on and reduced to writing for purposes of constructing, maintaining and operating the interconnection facilities. Also, FAC-002-1 imposes an obligation on the parties to coordinate and cooperate during the assessment of the reliability impact of the new interconnection facilities. Thus, FAC-001-0, at best, is a best practice or helpful initial guide to an entity considering interconnecting, but provides little, if any, meaningful value to reliability, especially when compared to the actual benefits to reliability via the FAC-002-1

Organization	Yes or No	Question 3 Comment
		studies, the execution of a negotiated agreement and the coordination of activities during construction and operation of the new facilities. Accordingly, FAC-001-0 should be retired, and, if necessary, the transfer of any requirements that protect reliability to FAC-002-1. All INT Standards (With the exception of INT-007-1 R1.2 which is part of and should remain in the Initial Phase.)Criteria B 6, 7 and 9 Statement: Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards. ALL DATA COLLECTION REQUIREMENTS NOT INCLUDED IN THE INITIAL PHASECIP-005-3a, -4a R5.3CIP-006-3c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4CIP-008-3, -4 R2PRC-018-1 R5Criteria B 1, 2 and 9Statement: These requirements are purely a data retention requirement with no functional nexus to reliability, and, therefore, are best handled via compliance monitoring, RSAWs or as a data request during an audit.ALL REPORTING OUT REQUIREMENTS NOT INCLUDED IN THE INITIAL PHASEEOP-002-3 R9.2EOP-004-1 R3 and its subrequirements; R4 and R5FAC-003-1 R3; FAC-003-1 R3.1: FAC-003-1 R3.2: FAC-003-1 R3.3: FAC-003-1 R3.4: FAC-003-1 R3.4.1: FAC-003-1 R3.4.2: FAC-003-1 R3.4.3: FAC-003-1 R4FAC-010-2.1 R5FAC-011-2 R5FAC-013-2 R6MOD-012-0 R2MOD-020-0 R1MOD-021-1 R3PRC-004-1a R3: PRC-004-2a R3: PRC-004-WECC-1 R.3.PRC-007-0 R2; PRC-007-0 R3; PRC-009-0 R2; PRC-011-0 R2; PRC-015-0 R3; PRC-016-0.1 R3; PRC-017-0 R2; PRC-021-1 R2TPL-001-0.1 R3; TPL-002-0b R3; TPL-003-0a R3; TPL-004-0 R2.Criteria B 1, 4 and 9Statement: There is no direct nexus between reporting out of information to an entity or Regional Entity and protecting reliability. If the Regional Entity desires to review information for purposes of monitoring reliability or assessing risk, the information should be collected via vehicles other than the Reliability Standards.Annual reviewsCIP-002-3, R3; CIP-002 -4 R3CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4 R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4

Organization	Yes or No	Question 3 Comment
		R9CIP-009-3, -4 R1EOP-005-1 R1; EOP-005-2 R3.1EOP-008-0 R1.7EOP-008-1 R5IRO-014-1 R4.3Criteria B 1, 2, 3, 7 and 9Statement: The annual review and update requirements are arbitrary, administrative and not aligned with the operation and protection of the Bulk Electric System. These requirements should be retired or modified to align with how the Bulk Electric System is operated and protected. OTHER REQUIREMENTSCIP-007-3, -4 R7 Criteria B 1, 2, 3 and 7Statement: The essential elements of the process of disposing or redeploying of Cyber Assets and the associated cyber security are set forth in R7.2 and R7.3. To require “formal methods, processes and procedures” appears to require formal documentation for the sake of documentation, rather than allowing the responsible entity to implement a process that achieves the actions required in R7.2 and R7.3, which may or may not include formal procedures, for example. EOP-004-1 R2Criteria B 7 Statement: The analysis of the BES for system disturbances is covered in the PRC-004-2.1a R1. The PRC Requirement R1 calls for the analysis of its transmission Protection System Misoperations. We believe that BES analysis is covered inherently through this PRC standard, making EOP-004 R1 redundant to the PRC standard. Another factor that was considered is the notable absence of any requirement in EOP-004-2 to analyze the BES disturbance. The focus of EOP-004 is on the reporting of applicable events that are identified in the PRC-004 standard. There is an event analysis reporting process referenced in the NERC Rules of Procedures (ROP) that addresses this requirement. Therefore, this is a redundant requirement. In February of 2012, NERC deployed its Events Analysis Process - incorporating the learnings from two field trials held over the previous year and a half. It includes all the necessary steps that affected operators must take to analyze and report on events that may impair the reliability of the BES. Most Regional Entities have already updated their reporting procedures to match NERC’s. Furthermore, NERC and the Regional Entities already have sufficient authority to order analyses and corrective action plans outside of the Reliability Standards. These are important steps for the development of Lessons Learned and trending analyses, but do not contribute to reliable operations. In fact, it is arguable that the demand for near term reporting - some within one hour of the

Organization	Yes or No	Question 3 Comment
		initiation of the event - interferes with the efforts of front-line personnel to mitigate the issue at hand BAL-004-0 (all requirements), BAL-005-0.1b R11; BAL-006-2 (all requirements)Criteria B 6 and 9Statement: BAL-004 requirement for time error correction is not important for reliability and should be eliminated. BAL-004 also duplicates NAESB standard WEQ-006.BAL-005 R11 states that Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE. This requirement is not needed for reliability. Ramp rates have minimal impact on ACE calculations, and are already included in the definition of Interchange Schedule in the NERC Glossary as used in R9. The requirement to use agreed upon ramp rates is commercial in nature and is already covered by NAESB standard WEQ-004-17.BAL-006-2 is an after the fact accounting of inadvertent interchange and does not impact reliability and should be eliminated. Consider augmenting NAESB standard WEQ-007. CIP-003-3, -4 R2 and its subrequirementsCriteria B 1 and 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether there is an employee called a CIP senior manager that oversees the plan. CIP-004-3, -4 R2.3 Criteria B 9Statement: Whether the entity has a robust up-to-date, trained-on CIP compliance plan may impact reliability, but not whether there is annual training. CIP-004-3, -4 R3.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether there is a seven year update to the personnel risk assessment(PRA). CIP-004-3, -4 R4.1Criteria B 1, 9Statement: Whether the entity has a robust up-to-date on CIP compliance plan may impact reliability, but not whether it reviews lists every seven days. CIP-005-3a, -4a R2.5 and its subrequirementsCriteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan to protect the ESP may impact reliability, but not whether specific information is documented. CIP-007-3, -4 R3.1, R3.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan to protect the PSP may impact reliability, but not whether specific information is documented within 30 days. Also, whether the entity has a robust up-to-date CIP compliance plan to protect the PSP may impact reliability, but

Organization	Yes or No	Question 3 Comment
		not whether specific information is documented. CIP-008-3 R1.4Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether specific information is documented within 30 days or a change. EOP-001-1b, -2bCriteria B 7Statement: Duplicative with the other EOP Standards (e.g., Capacity and Energy emergency of EOP-002, Load Shedding of EOP-003, and System Restoration of EOP-005).EOP-002-3 R1Criteria B 7Statement: Duplicative of other requirements such as IRO-001-1 R8, and should be retired or modified to reduce redundancy. EOP-002-3 R9 Criteria B 7Statement: When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources). It is duplicative of NAESB standard WEQ-008 and should be eliminated.EOP-005-2 R1.2.A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration. Criteria B 1, 3 and 7 Statement: With the implementation of NUC-001-2 R2, there is no longer a need for EOP-005-2 R1.2. Specifically, NUC-001-2 R2 requires Nuclear Plant Interface Requirements (NPIRs) to be included in the agreements for operation and maintenance (including restoration process) for off-site nuclear power:Ref: NUC-001-2 R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements1 that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.Given the off-site power requirements of NUC-001-2 which require comprehensive operational interface protocols (including restoration) between nuclear plants and responsible entities as part of the NPIRs, there is no longer a need for the administrative, documentation-only requirement in EOP-005-2 related to the same subject matter.FAC-013-1 (all requirements)Criteria B 6Statement: It is really a commercial planning practice suitable for Order 1000 under Section 205/206 as opposed to Section 215.IRO-002-2 (all requirements)Criteria B

Organization	Yes or No	Question 3 Comment
		7Statement: Redundant with COM-002-2, R1 COM-001-1.1, R1 and IRO-002-2, R2 and R3IRO-005-3a R10Criteria B 9Statement: Confusing requirement. It was intended to address rare cases where entities were told to operate to different SOLs and IROLs. However, since only the TOP and the RC can see these parameters, the only thing a GOP can do is follow a directive.IRO-014-1 R4Criteria B 9Statement: Requirement 4 (including sub-parts) should be rolled up into R1 and eliminated. Requirement 1 should be modified to require "current operating procedures, processes or plans with all adjacent RCs.IRO-015-1 R2.1Criteria B1 and 9Statement: Whether the procedure, process and plan is robust and up-to-date may impact reliability, not whether there are weekly calls. MOD-001-1 and MOD-008-1 (all requirements)Criteria B 6 and 9Statement: NERC should be focused on modeling the BES and managing SOLs and IROLs, the methodologies for the determination of CBM, TTC and ATC are commercial matters associated with the reservation and allocation of rights to transfer capability among transmission customers. While transfer capability calculations should be based on models of the BES, the NAESB WEQ should address the issues raised in MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12.Criteria B 6 and 9Statement: This could be handled as a data request from an RE or other Registered Entities, and therefore would not need a requirement, as there are too many requirements that warrant an attestation that no request was made.MOD-016-1.1 and MOD-021-1 (all requirements) Criteria B 9Statement: MOD-016 through MOD-021 are all about long term load forecasting and reporting of actual loads. Most of this can be eliminated from the standards and replaced with a data collection process (e.g., DADS). Loads to be used in modeling should be incorporated in the data requirements of MOD-010 and MOD-012 and not a separate standard.MOD-019-0.1 R1Criteria B 1, 2, and 9Statement: MOD-019-0.1 covers “Reporting of Interruptible Demands and Direct Control Load Management,” which requires reporting of a forecast of interruptible demand and direct control load management data. This reporting is administrative in nature, and the information is not important for reliability. The data is best gathered through DADS and not through a standard.MOD-028-1 (all requirements); MOD-029-1a (all requirements);

Organization	Yes or No	Question 3 Comment
		MOD-030-2 (all requirements)Criteria B 6 and 9Statement: Do the ATC / TTC standards belong in NERC or NAESB (i.e., MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12)? I think NERC should be focused on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc., and I think these can/should be moved to the NAESB standards. PRC-011-0 R1 Criteria B 4 and 9Statement: Requirements for maintenance of under-frequency load shedding systems ("UFLS") and under-voltage load shedding systems ("UVLS") are not needed to meet an adequate level of BES reliability. UFLS and UVLS installations are widely distributed. Distribution circuit outages, distribution field switching, and varying load profiles, such as peak and off-peak, could impact the amount of load that would be automatically shed by UFLS and UVLS. Therefore, entities must include adequate margins above their obligation to be able to meet the obligated load shed at all times as required by Reliability Standards, such as PRC-006 and PRC-007, that are performance-based, or results-based. While UFLS and UVLS are, of course, important safety-net systems, PRC-011-0 R 1 maintenance requirement is not needed to provide a "defense-in-depth" approach due to the margins required to meet performance-based requirements. Thus, Like PRC-008-0 R1 included in Phase I, Reliability Standard PRC-011-0 R1 which involves maintenance of UVLS, is not needed. In fact, it is typically the same relays and associated equipment that provides both the UFLS and the UVLS functions. PRC-022-1 R1, R1.1, R1.2, R1.3, R1.4, and R1.5Criteria B 7Statement: Whether the responsible entity has robust UVLS misoperation and correction action is redundant with PRC-004-1a, -2a. TOP-001-1a R7 (and its subrequirements)Criteria B 9Statement: For R3, there are three projects in progress addressing the issuance of directives by the RC, BA, and TOP. This includes COM-003-1's requirements for the issuances of "not quite directives" Also, for R7 All outages information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-002-2b R8 and R 9Criteria B 6, 7 and 9Statement: "Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency", is duplicative of VAR-001 (and incorrect) and should be eliminated. "Each Balancing Authority shall plan to meet Interchange Schedules and ramps", is duplicative of the

Organization	Yes or No	Question 3 Comment
		BAL standards and the NAESB standards and should be eliminated.TOP-002-2b R12Criteria B 6 and 9Statement: The ATC / TTC standards may belong in NAESB (i.e., MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12)? NERC standards should be focused on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc.TOP-002-2b R14 and R14.1Criteria B 9Statement: All derating information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-002-2b R15Criteria B 9Statement: Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations is a "how" requirement that is needed to meet other requirements in the standard. It is also not measureable, and the requirement should be eliminated. All weekly forecasts should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-003-1 R1 and its subrequirements; R2 and R3Criteria B 9Statement: All planned outage information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-005-2a R3Criteria B 9Statement: PSEs are not best positioned to provide reliability information.
SPP Standards Review Group		VAR-002 R3 Status changes on AVRs - Quite often status changes to AVRs may be made for only a matter of seconds. These changes do not impact the reliability of the BES but still require a call be made for notification of the change. Perhaps the requirement could be changed such that only status changes which impact the BES need to be reported. This hits on Items 4, 5, 8 and 9 in Criterion B.FAC-003-1 R1.3 - Specific training is required for personnel involved with vegetation management programs. This requirement is purely administrative (Criterion B.1) and does not, in and of itself, benefit the reliability of the BES. (Although this requirement has been removed in subsequent versions of this standard (FAC-003-2 and FAC-003-3), it remains in effect today. It needs to be retired.)While we don’t have an extensive list at this time, we would hope that the drafting team will ask for potential candidates which fit this category at some point in the future prior to the start of work on the latter phases of the project.

Organization	Yes or No	Question 3 Comment
Ameren		We support and agree with Trade Association's comments and their suggested list of Reliability Standard requirements to be retired or modified in the subsequent phase of the P81 Project. In addition, we suggest that IRO-005-3, R10 should be modify to eliminate its applicability to LSE and PSE in addition to GOP. While the IRO-005-3_1a, R10 is necessary for the reliable operation of the BES, its applicability to LSE and PSE also is questionable as these entities do not "operate" the BES. We believe that it is redundant (criteria B7) with other requirements where these entities (GOP, LSE, and PSE) have to follow the RC and/or TOP directives.
Wolverine Power Supply Cooperative, Inc.		Wolverine agrees with the list of requirements that the trade associations are submitting. We are a member of NRECA and agree with their comments.

4. **If you have any other comments or suggestions on the draft SAR that you have not already provided in response to the previous questions, please provide them here.**

Summary Consideration:

Comment

NERC staff requests that the scope of the SAR include currently-pending versions of related Reliability Standards to address requirements proposed in Phase I that are also included in a subsequent version of the standard that has been adopted by the NERC Board of Trustees, but not yet approved by FERC. Manitoba Hydro has a similar concern. NERC staff also requests that technical justifications only rely on Commission-approved Reliability Standards and how removal of a requirement will "increase in efficiency of the ERO compliance program" consistent with the language of P81.

Response

The P81 SDT added a footnote to the SAR to address how pending versions of related Reliability Standards (i.e., NERC BOT adopted) are considered so that eliminated requirements carry through to any new NERC BOT adopted versions. In addition, the P81 SDT is developing a technical white paper that it believes will provide a sound, technical basis for removal of each NERC Reliability Standard requirement proposed in Phase I. As appropriate, the technical basis will only reference or rely on Commission-approved Reliability Standards. The technical white paper being developed by the P81 SDT will generally address the issue of efficiency gains in the ERO compliance program with a blanket statement, on a requirement basis, or a combination of both.

Comment

Kansas City Power & Light states that the retirement of the requirements should not have a ripple impact in other standards or requirements.

Response

Although it is unclear to the P81 SDT what is meant by the term "ripple impact," it is believed to be similar to Criterion C's defense in depth concept. In the future, it would be helpful to provide some examples where the removal of a NERC Reliability Standard requirement may have a ripple impact in other standards. At this time, the P81 SDT believes the consideration of Criterion C (specifically, the consideration of whether retiring a requirement will have any negative impact on the defense-in-depth protection of the BES) ensures that other standards and requirements are not negatively impacted.

Comment

Entergy Services, Inc. states that during future phases industry input should be gathered in a more formal process. PPL Corporation NERC Registered Affiliates had a similar suggestion to increase stakeholder involvement.

Response

The P81 SDT is using the approved Standard Process Manual (SPM) for Phase I, and, at this point, plans to use the SPM in effect at the time for future phases of this project as well. The SDT acknowledges that stakeholder input may need to be gathered in a manner differently in subsequent phases than that used for Phase I, as subsequent phases may be more involved than simply removing requirements in their entirety and will likely require combining and/or re-wording of existing requirements.

Comment

Dominion observed some highlighting and number issues in the draft documents and appears to suggest we add IRO-001-1a R8.

Response

Requirement 8 of NERC Reliability Standard IRO-001-1a, while redundant to TOP-001-1a R3 with regard to Reliability Coordinators, will need to remain to ensure that a NERC Reliability Standard exists that addresses the need for entities to comply with a Reliability Coordinator's Reliability Directives.

Typographical errors will be addressed by the SDT.

The spreadsheet with proposed retirements on the NERC website will be manually sorted to ensure appropriate ordering of requirements on future revisions.

Comment

South Carolina Electric and Gas states that instead of retiring R2 of EOP-009-0 could the whole standard can be replaced by the new EOP-005?

Response

Yes, it is the SDT's understanding that NERC Reliability Standard EOP-009-0 will be retired when Standard EOP-005-2 becomes enforceable (July 1, 2013).

Comment

Idaho Power Company, among other things, suggests the combing of MOD standards 016 through 021.

Response

The suggested combining of NERC Reliability Standards MOD-016 through MOD-021 has been referred to the Question 3 sub-team for consideration for Phase II.

Comment

ACES Power Marketing Standards Collaborators and Electric Reliability Council of Texas, Inc. state that NERC needs to develop guidance that includes these criteria for drafting teams to avoid developing requirements that offer little reliability value in the future.

Response

The P81 SDT agrees that NERC-developed guidance is needed for standard drafting teams to ensure that new requirements consider the criteria established by the P81 SDT. The P81 SDT will address this issue with the NERC Standards Committee.

Comment

Georgia System Operations Corporation and Georgia Transmission Corporation suggest the consideration of requirements for retirement that supports NERC programs other than the mandatory Reliability Standards.

Response

The SDT appreciates the comments. The SDT believes that the criteria, as drafted, should capture those requirements that Georgia System Operations Corporation and Georgia Transmission Corporation are concerned about.

Organization	Yes or No	Question 4 Comment
NERC Staff Technical Review		(1) NERC Staff notes that the scope of the SAR should be expanded to include currently-pending versions of related Reliability Standards to address requirements proposed in Phase I that are also included in a subsequent version of the standard that has been adopted by the NERC Board of Trustees, but not yet approved by FERC. NERC Staff suggests that footnotes could be included to capture these situations.(2) NERC Staff submits that the technical justification for removal of particular requirements should not be a restatement of the Criteria (see e.g., INT-007-1 R1.2). Nor should the technical justifications reference and/or rely upon for support any Reliability Standards unless those Reliability Standards are Commission-approved. (3) NERC Staff suggests that the technical justifications for the satisfaction of the Criteria

Organization	Yes or No	Question 4 Comment
		should include an explanation of how removal of the requirement will result in an “increase in efficiency of the ERO compliance program” consistent with the language of P81.
Duke Energy		Duke Energy generally supports the comments submitted by The Edison Electric Institute (EEI) and the process being used to respond to the Commission’s invitation in the FFT Order.
Kansas City Power & Light		Efforts need to be made to make sure that the retirement of the requirements listed in "Proposed Requirements for Retirement in Phase 1 of Project 2013-02: Paragraph 81" don't have a ripple impact in other standards or requirements.
Entergy Services, Inc.		For future phases, indutry input should be gathered in a more formal process to allow for suggestions for re-wording or suggesting additional requirements for removal.
Tucson Electric Power		I appreciate the fact that there is a review of the NERC Standards as well as a review of the absolute need for various Standards and/or requirements. I also appreciate that the regulatory bodies are agreeable to such changes and improvements to the compliance process.
Illinois Municipal Electric Agency		Illinois Municipal Electric Agency fully supports this initiative by the collaboration group which suppports NERC's application of a risk-based focus to it's programs, and which is consistent with SPIG Recommendation 4.
Dominion		In the Complete Set of Standards with Proposed Retirements for Phase 1 pdf; Need to add IRO-001-1a R8 and MOD-004-1 R8 needs to be completely highlighted. In the Spreadsheet with Proposed Retirements; Suggest the MOD-004-1 Requirements be put in numeric order. Need to add IRO-001-1a R8; it is not listed on the spreadsheet.
South Carolina Electric and Gas		Instead of retiring R2 of EOP-009-0 could the whole standard can be replaced by the new EOP-005?

Organization	Yes or No	Question 4 Comment
Manitoba Hydro		It is not clear what will happen in instances where this project proposes to remove a requirement from a FERC approved Reliability Standard when the NERC BOT has already approved a newer version of that same standard. Will the newer BOT approved version also be modified if it includes one of the requirements in question? What if industry has already resolved one of these issues in the next version of a standard? Shouldn't we just implement the newer version?
MidAmerican Energy Company		MidAmerican Energy Company supports the draft SAR as a positive step to allow Responsible Entities, Regional Entities, NERC and FERC to focus their combined efforts on protecting the Bulk Electric System.
Idaho Power Company		MOD standards 016 through 021 should be combined into a single standard, removing duplication and retiring requirements which are "reporting-only" and/or have little discernable reliability benefit.We agree with the stated Purpose or Goal of the proposed standard of setting forth specific Reliability Standard requirement evaluation criteria and establishing a multi-phased process for addressing these Reliability Standard requirements. We agree with and support this Reliability Standard requirement evaluation and proposed multi-phased process based on the following:We believe there is value in differentiation of violations based on risk. We believe that not all violations pose the same risk to reliability, so they should not all be treated the same. Focusing on the greatest risks to reliability will allow for more efficient use of resources while improving the reliability of the BES through an application of structured risk management.
ACES Power Marketing Standards Collaborators		NERC needs to develop guidance that includes these criteria for drafting teams to avoid developing requirements that offer little reliability value in the future. There are many standards currently being developed that include similar kinds of requirements that will make a future exercise like this necessary. NERC should expend every effort to avoid such a future situation. Some examples can be found in Project 2007-09 Generator Verification. Proposed MOD-027-1 R3 through R5 largely

Organization	Yes or No	Question 4 Comment
		memorializes the administrative interactions that must occur between the GO and TP to develop a good active power/frequency control model. PRC-004-3 Part 4.2 in Project 2010-05.1 Misoperations is another example. It requires maintenance of data regarding Corrective Action Plans. These are administrative requirements and are unnecessary.
CPS Energy		No additional comments.
Independent Electricity System Operator		No comments.
Occidental Energy Ventures Corp.		OEVC Agrees with the Trade Associations on this response.
Pepco Holdings Inc & Affiliates		Pepco Holdings Inc supports this project. Additionallyl Pepco Holdings Inc supports the comments provided by EEI.
Georgia System Operations Corporation		Reliability Standard requirements are those that provide for Reliable Operation, including without limiting the foregoing, requirements for the operation of existing Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation. NERC administers other programs, such as industry alerts, reliability assessments, event and trend analyses, education, and monitoring and enforcing Reliability Standards. These other programs are designed to work in concert with Reliability Standards to support reliable operation. NERC requirements relating to administering these other programs are very important but are not Reliability Standard requirements.One of the criteria for evaluating the elimination of a Reliability Standard requirement is that it is purely reporting. There are a number of NERC requirements for these other NERC programs embedded in Reliability Standards. Most of them are purely reporting. However, to the extent that there may be other requirements for these NERC programs embedded that are not purely

Organization	Yes or No	Question 4 Comment
		reporting, they should also be considered for elimination. Reliability Standards by definition are not mechanisms for the administration of those other NERC programs.
Georgia Transmission Corporation		Reliability Standard requirements are those that provide for Reliable Operation, including without limiting the foregoing, requirements for the operation of existing Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation. NERC administers other programs, such as industry alerts, reliability assessments, event and trend analyses, education, and monitoring and enforcing Reliability Standards. These other programs are designed to work in concert with Reliability Standards to support reliable operation. NERC requirements relating to administering these other programs are very important but are not Reliability Standard requirements.One of the criteria for evaluating the elimination of a Reliability Standard requirement is that it is purely reporting. There are a number of NERC requirements for these other NERC programs embedded in Reliability Standards. Most of them are purely reporting. However, to the extent that there may be other requirements for these NERC programs embedded that are not purely reporting, they should also be considered for elimination. Reliability Standards by definition are not mechanisms for the administration of those other NERC programs. GTC recommends identifying these requirements (ex. MOD-016 through 021) and appending them to the Phase I list.
seattle city light		Seattle City Light supports the consolidated comments of the industry Trade Organizations.
Tampa Electric Company		Tampa Electric recommends that the P81 DT ensure that the CIP requirements proposed for removal via P81 are also removed from v5 of the NERC CIP standards. Tampa Electric also supports the consideration of the following for NERC CIP standards: Removal of data collection requirements: CIP-005-3a, -4a R5.3CIP-006c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4; R7.3CIP-008-3, -4 R2Removal of annual review requirements: CIP-002-2, -4 R4CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4

Organization	Yes or No	Question 4 Comment
		R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4 R9CIP-009-3, -4 R1
Transmission Agency of Northern California		TANC commends FERC for soliciting input on ways to eliminate requirements that are redundant or provide little protection for the bulk power system. TANC believes that NERC has proposed an appropriate response to this opportunity and looks forward to further initiatives that prioritize reliability ahead of compliance.
SERC EC Planning Standards Subcommittee		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
SPP Standards Review Group		The following are typos we found in the SAR:Either delete the ‘an’ or make ‘processes’ singular in Technical Criteria B.2.(b).Either delete the ‘that’ in the 5th line or the ‘to’ in the 6th line of the Statement paragraph under CIP-001-2a R4. This is the 3rd sentence in the paragraph.Insert an ‘a’ between ‘require’ and ‘new’ in the last sentence of the Statement paragraph under CIP-003-3, -4 R4.2.
City of Austin dba Austin Energy		The P81 project should be considered a high priority Standards development project for the following reasons:(1) Responsive to P81 of FERC’s March 15, 2012 order and SPIG Recommendation No. 4(2) Will increase efficiency of the ERO compliance programs(3) Requirements submitted for the initial phase appear to be clear candidates on their face and should not require extensive technical research(4) The collaborative nature of the project is an example for future work, because it advances the project while reducing the impact on stakeholders and NERC staff(5) The proposed pace of the project sets an example for future work (6) Furthers the focus on results, performance based Reliability Standards (7) May provide a roadmap of what should or should not be a requirement in future Reliability Standards(8) The draft P81 SAR criteria is designed to be sufficiently broad to capture all FERC approved reliability Standards that are unnecessary, redundant or do little to protect reliability (9) To eliminate Reliability Standards requirements that deter from our

Organization	Yes or No	Question 4 Comment
		focus on reliability Based on these benefits, we support the Standards Drafting Team and NERC staff working together to file the initial list of Reliability Standards for retirement with the Federal Energy Regulatory Commission prior to the end of the year and that the Standards Drafting Team also make significant progress on the scope of the phase two P81 Reliability Standards list by the end of the year.
PPL Corporation NERC Registered Affiliates		The PPL Companies generally support the concept and process being recommended, but are concerned that the stakeholder involvement in the process may be lacking. During the webinar on August 21, 2012 the drafting team members stated that the Standards Development Process will be utilized for all Phases of the project. However, the SAR does not indicate that the SDP is mandated. The Companies recommend that the entire SAR specifically state the the Standards Development Process will be used where the SDT must respond to comments and a stakeholder vote for approval. Additionally, the process should allow for individual (or groups) of stakeholders to request a standard's removal or modification that is not designated by the SDT for removal.
The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA) (collectively, the Trade		The Trade Associations believe that the P81 project should be considered a high priority Standards development project for the following reasons: o Responsive to P81 of FERC's March 15, 2012 order and SPIG Recommendation No. 4 o Will increase efficiency of the ERO compliance programs o Requirements submitted for the initial phase appear to be clear candidates on their face and should not require extensive technical research o The collaborative nature of the project is an example for future work, because it advances the project while reducing the impact on stakeholders and NERC staff o The proposed pace of the project sets an example for future work o Furthers the focus on results, performance based Reliability Standards o May provide a roadmap of what should or should not be a requirement in future Reliability Standards o The draft P81 SAR criteria are designed to be sufficiently broad to capture all FERC approved reliability Standards that are unnecessary, redundant or do little to protect reliability o Eliminating Reliability Standards requirements that are unnecessary, redundant or do little to protect reliability will

Organization	Yes or No	Question 4 Comment
Associations).		eliminate distractions from our focus on reliability Based on these benefits, the Trade Associations strongly support the Standards Drafting Team and NERC staff working together to file the initial list of Reliability Standards for retirement with the Federal Energy Regulatory Commission prior to the end of the year, and that the Standards Drafting Team also make significant progress on the scope of the phase two P81 Reliability Standards list by the end of the year.
City of Garland		This is a good start on removing requirements that are either redundant or provide little / no protection for Bulk-Power System reliability.
Electric Reliability Council of Texas, Inc.		This SAR offers significant potential value by retiring requirements that provide no BES reliability value, but nonetheless require commitment of time and resources for both regulated entities and regulators to effect and oversee compliance, respectively, and also pose liability risk for no reason, given that they provide no reliability value. However, the substance of the requirements (e.g. administrative processes, etc.) may have non-essential value unrelated to system reliability. To the extent the SDT/industry/NERC believe there may be some non-mandatory use for this information outside of the reliability standards, the information could be considered for guidance in another format, such as guidelines, best practice documentation or lessons learned. If such an effort is deemed worthwhile, it should be established in a separate process/effort, and should not distract from moving this and future phases of this SAR forward in the most efficient and effective manner to achieve the significant benefits that may result from this SAR. In addition, the standards process going forward should include consideration of whether a proposed standard addresses a reliability requirement, is cost effective and meets the reliability-based standards criteria of “what” needs to be met and not “how” an entity will meet the standard which is better address through guidelines, best practices and/or lessons learned.
Central Husdon Gas & Electric		We agree with the criteria as listed, however, we believe that another criterion must be added. This criterion is that the retirement of a requirement must not create a

Organization	Yes or No	Question 4 Comment
Corporation		compliance gap for Entities. Several of the NERC requirements have been crafted to afford Entities a means to display compliance. Retirement of these requirements can place an Entity's compliance efforts in jeopardy. A salient example of this is identified below:Central Hudson Gas & Electric Corporation strongly disagrees with the inclusion of CIP-003-3, -4 Requirements R3, R3.1, R3.2, R3.3 as candidates for retirement. The reasons stated in the SAR in favor of inclusion are that these requirements are administrative in nature and are purely examples of a documentation process. Further it is stated in the SAR that they, ".... have been subject to misinterpretation, including responsible entities believing they can exempt themselves from compliance with the CIP requirements." This last statement is precisely the reason why the aforementioned requirements were included in the standard. These requirements allow Registered Entities to, on rare occasions, take an exception to one or several of the CIP requirements (for a limited period of time) if they (1) have valid cause (major emergency, Force Majeure, etc.), (2) document the occurrence and (3) are reviewed and approved by the CIP Senior Manager. This process supports the Registered Entity's compliance effort and acknowledges the need for special protocols to address emergency circumstances. Without such a process, the only recourse for the Registered Entity is to self-report a violation which is not within its control. In other words, retirement of these requirements would force the Registered Entity to be in full compliance with ALL CIP Standards ALL the time regardless of circumstance. The concept of 'realistic expectation' was undoubtedly the reason these requirements were crafted and included in the standard. Further, with regard to the Registered Entity's decision to claim an exception, a system of checks and balances already exists. At the time of a compliance audit of the standard's requirements, the Regional Entity reviews and makes a determination as to whether the actions taken by the Registered Entity were warranted.
NV Energy		We commend NERC and the Drafting Team on their efforts thus far in this important initiative. This process will serve to better focus the industry's limited resources on

Organization	Yes or No	Question 4 Comment
		activities that are necessary for reliability.
SRC		We support the P81 team's efforts and appreciate the effort to pull together this initial list of criteria and requirements. The SRC is looking forward to seeing a concrete timeline for the project.
Western Electricity Coordinating Council		WECC recognizes and appreciates the large amount of work done in a short time on this project and appreciates the opportunity to proved our comments.
American Electric Power		While AEP supports the efforts of this drafting team, it might have been advantageous to first agree on the criteria as a first phase, and then once determined, enter a second phase where requirements were proposed based upon the agreed-upon criteria. This might enable the fast-tracking of the criteria to be used by other concurrent projects and project teams.

END OF REPORT