NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Meeting Agenda
Project 2010-07 Generator Requirements at the Transmission Interface

November 30, 2011 | 1:00–5:00 p.m. ET
December 1, 2011 | 8:00 a.m.–5:00 p.m. ET

NERC
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Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement*

Agenda

1. **Review Meeting Goals**
2. **Review Comment Report***
    a. Identify overarching themes
    b. Develop responses
        i. Identify those outside of scope of the Standard Drafting Team (Standard Authorization Request and registry comments)
        ii. Identify those that warrant further discussion
    c. Make conforming changes
        i. FAC-001-1*
        ii. FAC-003-3*
        iii. PRC-004-2.1*
    d. Prepare for recirculation ballot?
3. **Discuss Other Inputs**
    a. FERC Order Denying Rehearing and Partially Granting Clarification Order for Milford/Cedar Creek*
    b. NERC compliance perspective

c. Bulk Electric System definition project

4. **Determine Next Steps**

    a. Definition changes?

    b. Additional standard modifications?

5. **Other Business**

6. **Adjourn**

*Background materials included.

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Consideration of Comments

Project 2010-07 Generator Requirements at the Transmission Interface

The Generator Requirements at the Transmission Interface Drafting Team thanks all commenters who submitted comments on the first formal posting for Project 2010-07—Generator Requirements at the Transmission Interface. These standards were posted for a 45-day public comment period from October 5, 2011 through November 18, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 40 sets of comments, including comments from 123 different people from approximately 86 companies representing all 10 of the 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:

http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html

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, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal? …. .... *X*

8. If you answered "yes" to Question 7, are the modifications the SDT has made in this posting the appropriate ones? …. .... *X*

9. If you answered "no" to Question 7, what standards need to be added or removed to achieve the SDT's goal? Please provide technical justification for your answer. …. .... *X*

10. Do you have any other comments that you have not yet addressed? If yes, please explain. …. ...... *X*

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	Gerald Beckerle	SERC OC Standards Review Group	X		X							

1.	Scott Brame	NCEMC	SERC	1, 3, 4, 5
2.	Troy Willis	Georgia Transmission Corp.	SERC	1
3.	Mike Hirst	Cogentrix	SERC	5
4.	Bob Dalrymple	TVA	SERC	1, 3, 5, 6
5.	Matt Carden	Southern Co.	SERC	1, 5
6.	Shardra Scott	Gulf Power Co.	SERC	3
7.	Kerry Sibley	Georgia Transmission Corp.	SERC	1
8.	Andy Burch	EEI	SERC	5
9.	Shaun Anders	City of Springfield (CWLP)	SERC	1, 3
10.	Melinda Montgomery	Entergy	SERC	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	John Troha	SERC Reliability Corp	SERC 10										
2.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Robert Rhodes	Southwest Power Pool	SPP	2
3.	Don Taylor	Westar	SPP	1, 3, 5, 6
4.	John Allen	City Utilities of Springfield	SPP	1, 4
5.	Sean Simpson	MCPBPU	SPP	1, 3, 5
6.	Louis Guidry	CLECO	SPP	1, 3, 5
7.	Mitch Williams	Western Farmers	SPP	1, 3, 5
8.	Valerie Pinnamonti	AEP	SPP	1, 3, 5
9.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
10.	Terri Pyle	OGE	SPP	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Guy Zito, Guy Zito	Northeast Power Coordinating Council, Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC, NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC, NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC, NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC, NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC, NPCC	8
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC, NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC, NPCC	2
9.	Chantel Haswell	FPL Group, Inc.	NPCC, NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC, NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC, NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC, NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC, NPCC	6
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC, NPCC	10

15.	Robert Pellegrini	The United Illuminating Company	NPCC, NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC, NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC, NPCC	5
18.	Saurabh Saksena	National Grid	NPCC, NPCC	1
19.	Michael Schiavone	National Grid	NPCC, NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC, NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC, NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC, NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC, NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X
No additional members listed.													
5.	Group	Will SMith	MRO NSRF	X	X	X	X	X	X	X			X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Jodi Jenson	WAPA	MRO	1, 6
4.	Ken Goldsmith	ALTW	MRO	4
5.	Alice Ireland	XCEL/NSP	MRO	1, 3, 5, 6
6.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
7.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
8.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
9.	Scott Nickels	RPU	MRO	4
10.	Terry Harbour	MEC	MRO	1, 3, 5, 6
11.	Marie Knox	MISO	MRO	2
12.	Lee Kittelson	OTP	MRO	1, 3, 4, 5
13.	Scott Bos	MPW	MRO	1, 3, 5, 6
14.	Tony Eddleman	NPPD	MRO	1, 3, 5
15.	Mike Brytowski	GRE	MRO	1, 3, 5, 6
16.	Richard Burt	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pat Huntley	SERC	SERC	10
2.	John Sullivan	Ameren Services Co.	SERC	1
3.	Philip Kleckley	SC Electric & Gas Co.	SERC	1
4.	Bob Jones	Southern Company Services	SERC	1
5.	Jason Adams	TVA	SERC	1

				1	2	3	4	5	6	7	8	9	10
7.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

				1	2	3	4	5	6	7	8	9	10
8.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea	Dominion Resources Services, Inc.	RFC	5, 6
2.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6
3.	Michael Crowley	Virginia Electric and Power Company	RFC	1, 3

				1	2	3	4	5	6	7	8	9	10
9.	Group	Annette M. Bannon	PPL NERC Registered Affiliates			X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brent Ingebrigston	LG&E and KU Services Co.	SERC	3
2.	Don Lock	PPL Brunner Island, LLC	RFC	5
3.		PPL Martins Creek, LLC	RFC	5
4.		PPL Holtwood, LLC	RFC	5
5.		PPL Montour, LLC	RFC	5
6.		Lower Mount Bethel Energy, LLC	RFC	5
7.	Annete Bannon	PPL Susquehanna, LLC	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Leland McMillan	PPL Montana, LLC	WECC 5										
10.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators										
	Additional Member	Additional Organization	Region / Segment Selection										
1.	Mohan Sachdeva	Buckeye Power	RFC 3, 5, 6										
2.	Erin Woods	East Kentucky Power Cooperative	SERC 1, 3, 5, 6										
3.	Michael Brytowski	Great River Energy	MRO 1, 3, 5, 6										
11.	Group	Steve Rueckert	Western Electricity Coordinating Council										X
No additional members listed.													
12.	Individual	Jack Cashin	Electric Power Supply Association					X	X				
13.	Individual	Natalie McIntire	American Wind Energy Association					X					
14.	Individual	Tom Flynn	Puget Sound Energy, Inc.	X				X	X				
15.	Individual	Silvia Parada Mitchell	Compliance & Responsbility Organization	X		X		X	X				
16.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
17.	Individual	Chris Higgins/Stephen Enyeart/Chuck Mathews/Charles Sheppard	Bonneville Power Administration	X		X		X	X				
18.	Individual	Thad Ness	American Electric Power	X		X		X	X				
19.	Individual	Carla Bayer	BP Wind Energy North America Inc.					X					
20.	Individual	John Bee on behalf of Exelon	Exelon	X				X					
21.	Individual	Dennis Sismaet	Seattle City Light	X		X	X	X	X				
22.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP (Occidental Chemical)					X					
23.	Individual	Michael Falvo	Independent Electricity System Operator		X								
24.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
25.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Kirit Shah	Ameren	X		X		X	X				
27.	Individual	John Seelke	PSEG	X		X		X	X				
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
29.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
30.	Individual	Ravi Bantu	RES Americas Development					X					
31.	Individual	Katy Wilson	Sempra Generation					X					
32.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
33.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
34.	Individual	Ed Davis	Entergy Services	X		X		X	X				
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
36.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
37.	Individual	Anthony Jablonski	ReliabiltiyFirst										X
38.	Individual	Donald Jones	Texas Reliability Entity										X
39.	Individual	Amir Hammad	Constellation Power Source Generation					X					
40.	Individual	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

1. **Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT's rationale for its changes.)**

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner's radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term "Facility" is used. Moreover, the Technical Justification document's reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC's registration of GOs as TOs.
Response:		
Southern Company	No	â€,1) R4 is duplicative of R1 - either remove "maintain" from R1 or delete R4 - both instances of "maintain" are not needed.â€, 2) The measures, as written, provide no additional indication of the evidence that could be presented to demonstrate compliance with the Reliability Standard Requirements. They provide little guidance on assessing non-compliance with the Requirements. â€,
Response:		

Organization	Yes or No	Question 1 Comment
Southwest Power Pool Standards Development Team	No	Based on the applicability section of FAC-001 we feel that the strike through should have been kept. It limited the requirement to just those generator owners who had agreements in place, which we feel is appropriate.
Response:		
Texas Reliability Entity	No	In Section 5.1, the reference to Regional Entity should be removed. There are no requirements that apply to the Regional Entity.In Requirements R1 and R4, “Planning Coordinator” should be added after “Regional Entity.” In the ERCOT Region it is the Planning Coordinator that maintains planning criteria and connection requirements.There is no NERC requirement or any obligation (as indicated in the technical justification document) on the part of a GO to specifically execute an Agreement to evaluate the reliability impact of interconnecting a third party Facility. Therefore, this requirement’s applicability is contingent on a prerequisite that may not occur, and that is under the control of the GO. This assumption on the part of the SDT unnecessarily complicates the compliance monitoring and enforcement of this standard. For instance, if an “Agreement” is not executed, a GO is not required to comply with the requirement, even though the GO may ultimately interconnect with another entity. The requirement should be modified to include an applicability trigger similar to that of FAC-002-1, so that once a GO “seek[s] to integrate . . .,” i.e., agrees to or is compelled to allow a third-party interconnection, then the requirement becomes applicable. Otherwise, the compliance and monitoring is subject to the SDT’s speculation as indicated in this language included in the technical justification document: “However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a

Organization	Yes or No	Question 1 Comment
		third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement.”
Response:		
Manitoba Hydro	No	Manitoba Hydro has the following comments:1) The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.2) If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO

Organization	Yes or No	Question 1 Comment
		obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, 'interconnection requests for Generator Owner Facilities are still relatively rare.3) If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.4) The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to

Organization	Yes or No	Question 1 Comment
		comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to "coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority". Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not be required.5) Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.
Response:		
Tennessee Valley Authority	No	Suggest that the overall structure of the standard be revised such that R1 - R3 are applicable to the Transmission Owner (consistent with existing FAC-001-0) and R4 (the new requirement) is applicable to the "applicable Generator Owner". See further comments below. Support the proposed revisions to R1 and R4, but suggest R4 be returned to R3 (consistent with existing FAC-001-0).R3 in the balloted standard should be returned to R2 (consistent with existing FAC-001-0) and only be applicable to the Transmission Owner. R3.1 (or R2.1 if moved back) should be "fixed", but it may be beyond this SDT's charge. The use of "above" in the FAC-001-0 standard, or the proposed reference to "Requirements R1 or R2" in the proposed standard do not make sense in combination with the colon used at the end of the requirement. Suggest that R3.1 (or 2.1 if moved back) be revised as written below and all sub-requirements of R3.1 be elevated (R3.1.1 becomes R3.2, R3.1.2 becomes R3.3, etc.)."R3.1 Performance requirements and/or planning criteria used to assess system impacts." R2 in the balloted standard should become R4 and modified to incorporate the

Organization	Yes or No	Question 1 Comment
		connection requirements contained in R3 that can more reasonably be expected of an "applicable Generator Owner". For instance, an "applicable Generator Owner" might simply have a connection requirement for a third party that addresses coordination of system impact studies with the appropriate Transmission Owner(s), in lieu of R3.1, R3.1.1, and R3.1.2. Suggest that R2 (or R4 if moved below existing FAC-001-0 requirements) be revised as written below."R2 Each applicable Generator Owner that has agreed to allow a third party Facility owner (Generation Facility, Transmission Facility, or End-user Facility) to connect to the Transmission system through use of pre-existing applicable Generator Owner Facilities shall communicate it's Facility connection requirements to the third party. The applicable Generator Owner Facility connection requirements shall address the following items: R2.1 Coordination of system impact studies with the Transmission Owner. R2.2 Voltage level and MW and MVAR capacity or demand at point of connection. R2.3 Breaker duty and surge protection. R2.4 System protection and coordination R2.5 Metering...." Etc.
Response:		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	No	The intent of the draft language in FAC-001-1 is to provide guidance for addressing the alleged reliability gap that exists between GO/GOPs that own/ operate transmission facilities but are not registered as TO/TOPs. The impact of the revised language will depend on the characterization of the generator lead after the "third party " connects to the existing generator lead. IF the generator lead is owned by the TO utility after the third party connection : The proposed DRAFT FAC-001 language suggests that within 45 days of a 3rd party having an executed Agreement to evaluate the reliability impact of interconnecting, the existing generator needs to document and publish facility connection requirements. The proposed language suggests that a third party can commandeer existing generators leads and

Organization	Yes or No	Question 1 Comment
		interconnect. A reclassification would be required because “third party” power would flow through the downstream portions of the existing leads. This introduces significant challenges for defining ownership / transfer of installed assets as well as real property, easements, operational jurisdiction, O&M cost responsibility, etc. The FERC approved pro-forma Attachment X Interconnection Agreement clearly states that the project Developer must meet all Applicable Reliability Standards which means that all requirements and guidelines of the Applicable Reliability Councils, and the Transmission District to which the Developer’s Large Generating Facility is directly interconnected. As an example, to accommodate this NERC proposal, the FERC approved NYISO pro-forma tariff would need to be revised to allow this “third party” use. The pro-forma interconnection tariff also states that the Developer must provide updated project information prior to the Facilities Study. The Facilities Study might not be made until several years after the Interconnection Request /Feasibility Study is made (“executed Agreement to evaluate the reliability impact of interconnecting” in this proposed draft is akin to the Interconnection Request/Feasibility Study). Placing the requirement to have the existing Generator Owner publish reliability requirements for a potential “third party user”, without the generator having any knowledge of the potential reliability outcomes or asset transfer / ownership issues is not a reasonable expectation. The interconnection of a third party to an existing generator lead would force existing generators to revise their Interconnection Agreements with FERC. The “third party”, would at a minimum, need to comply with the existing Generators reliability obligations as specified in the Interconnection Agreement.IF the third party connects to the GO owned generator lead, the GO will be considered a TO:A TO would not be involved, other than review of the SRIS and Facilities reports. The difficult thing for an existing GO would be to prepare, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the

Organization	Yes or No	Question 1 Comment
		Generator Owner's existing Facility, a document listing the requirements. To allow for the above possibilities, the language for applicability of FAC-001 to GO's or GOP's, should be :"Each applicable Generator Owner shall, at least 60 days prior to execution of a Facilities / Class Year Study Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System, document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements."
Response:		
Consolidated Edison Co. of NY, Inc.	No	The language for FAC-001 Requirement R2 should be:"This requirement shall apply to each applicable Generator Owner. Generator Owner filings must be made at least 60 days in advance of execution of the final interconnection study agreement in the Planning Coordinator's or Transmission Planner's study process.Each applicable Generation Owner must publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.The evaluation of the reliability impact(s) of interconnecting a third party Facility to the Generator Owner's existing Facility utilized for interconnection to the Transmission System must be documented."
Response:		
Ingleside Cogeneration LP	No	Unfortunately, the vital point of this requirement revolves around whether

Organization	Yes or No	Question 1 Comment
(Occidental Chemical)		or not a Generator Owner is compelled externally to allow access to their interconnection facilities. If the GO is driving the connection for financial or other business reasons, there is no reason they should not be responsible for developing AND maintaining a facility connection requirements document. Otherwise, when the local transmission system requirements change for any reason, there will be no entity responsible to ensure that the third party will conform as well.Conversely, if the GO should be compelled to allow access to a third party, it is the responsibility of the "compeller" to handle all the related reliability studies and documents. This may include the development of a CFR which separates reliability tasks between the GO and other entities - especially if a TSP registration is required. This ensures that the Regional Entity, PUC, RTO, or other regulator must budget dollars and resources directly related to their action - not cause them to be directed to a GO.
Response:		
PSEG	No	We revised this partial sentence to the following: "Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Transmission Facility that is used for connection to the interconnected Transmission systems (under FAC-002-1), ..."- The phrase "Generator Owner's existing Facility that is used to interconnect to the Transmission System" was changed to "Generator Owner's existing Transmission Facility that is used for connection to the interconnected Transmission systems." - "Transmission" was added before Facility to exclude connections elsewhere; "Transmission System" was changed to "Transmission systems" because while "Transmission" and "System" are defined in the NERC Glossary, "System" means "A combination of generation, transmission, and distribution components." "Transmission

Organization	Yes or No	Question 1 Comment
		systems" do not have generation or distribution components, so a lower case "system" is warranted. - In addition, the suggested phrase "interconnected Transmission systems" (plural "systems") uses identical language from FAC-002-1, except that we capitalized "Transmission.
Seattle City Light	Affirmative	Key points are that (1) an executed agreement is required before evaluations of impacts are necessary and (2) this only applies when a third party is connecting to the generating interconnection line.
Response:		
Electric Power Supply Association	Yes	All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, "If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility" then FAC-001-1 should apply. EPSA concurs with SDT's conclusion.The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.

Organization	Yes or No	Question 1 Comment
Response:		
American Wind Energy Association	Yes	AWEA appreciates that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, AWEA believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
Response:		
SERC OC Standards Review Group	Yes	Please verify within the applicability section (4.2.1) you intended to use the word "within" rather than some other wording.
Response:		
RES Americas Development	Yes	RES Americas and AWEA appreciate that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a

Organization	Yes or No	Question 1 Comment
		burdensome and hard to meet deadline for GO/GOP staff. However, we believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
Response:		
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the changes the drafting team made but believe some additional changes are necessary. In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
Response:		
Southwest Power Pool Regional Entity	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 1 Comment
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	

Organization	Yes or No	Question 1 Comment
Constellation Power Source Generation	Yes	
ReliabiltiyFirst		
Entergy Services		
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		

2. **Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?**

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Ingleside Cogeneration LP (Occidental Chemical)	No	Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify how the requirements apply to an in-place "executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System." In the view of Ingleside Cogeneration LP, if the Agreement takes effect even one day before FAC-001-1 does, requirements R2 and R3 do not apply. Without this clarification, it is possible that NERC's Compliance team will apply the requirements retroactively - with minimum industry input.
Response:		
Southwest Power Pool Regional Entity	No	No action is required unless a GO has an executed third-party agreement. If a GO has an agreement, the standard already includes a 45-day timeframe for the GO to document and publish its facility connection requirements.
Response:		
Southern Company	No	See our response to Question 9.
Response:		
Manitoba Hydro	No	See question 1 comments.

Organization	Yes or No	Question 2 Comment
Response:		
Cowlitz County PUD	Yes	Cowlitz PUD (District) registered as a Transmission Owner shortly before FAC-001-0 became effective and was forced to file a Mitigation Plan in order to facilitate compliance. The District successfully completed compliance implementation and documentation in eight months. The proposed one year compliance timeframe is sufficient.
Response:		
Seattle City Light	Yes	The proposed changes for FAC-001-1 state a 45 day period to complete the evaluation. Not sure what the question is referring to regarding " 1 year "?
Response:		
American Wind Energy Association / RES Americas Development	Yes	Yes, since there is no exigent reason why this standard needs to be put in place at once, we support the one-year compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.
Response:		
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 2 Comment
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
PSEG	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		

Organization	Yes or No	Question 2 Comment
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabiltiyFirst		
Texas Reliability Entity		

3. **With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "…that extends greater than one mile beyond the fenced area of the generating station switchyard…" We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.**

   Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3?

Summary Consideration:

Organization	Yes or No	Question 3 Comment
Ameren Services	Negative	(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance. (b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO

Organization	Yes or No	Question 3 Comment
		is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance. (c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years
Response:		
Lee County Electric Cooperative	Negative	R1.2 refers to an encroachment due to a fall in. This is confusing because according to the dictionary “Webster’s II” encroachment reads: “to intrude gradually”, and a ‘fall in’ is not usually gradual.
Response:		
Wisconsin Public Service Corp.	Negative	The concern with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid

Organization	Yes or No	Question 3 Comment
		observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: A two kilometer distance from the controlled area perimeter.
Response:		
Florida Reliability Coordinating Council	Negative	There is no technical justification for excluding 1 mile beyond the fence in the applicability of generators.
Response:		
Southern Company	No	â€‚All of these comments pertain to FAC-003-3: 1) We suggest referring to the Implementation Plan in the Effective Date sub-section of Section A of the standard rather than repeating the content of the Implementation Plan in the standard. There exists unessary duplication with including the information in both places. 2) We suggest simplifying the purpose statement to more succinctly say the intent, for example: "To maintain a reliable transmission system by managing vegetation located on transmission rights of way to minimize vegetation encorachments and thereby minimize the risk of vegetation related outages". If this change is not acceptable, at least change the phrase "preventing the risk" to "minimizing the risk". 3) We feel that the Enforcement paragraphs between 4.3.1.3 and 5.0 seem to be out of place. Those paragraphs don’t belong in this location - consider moving them

Organization	Yes or No	Question 3 Comment
		to Section C. Compliance. The fourth paragraph belongs in the background section. 4) We suggest moving the background section to Section F. "Associated Documents". It gets in the way of getting to the requirements of the standard. 5) We suggest moving Table 2 of the "Guideline and Technical Basis" document into R1, since it seems to be the only part of the document that is enforceable. Further we suggest that the Guideline and Technical Basis document be removed from the standard. The inclusion of this document in the standard makes the standard unweildy. 6) We suggest reordering the words in R1 to more clearly state the requirement. Please consider this rephrasing: "For lines which are either an element of an IROL or an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within their Rating during all Rated Electrical Operating Conditions of the types shown below:..." (remainder is unchanged). 7) We suggest reordering the words of R2 to more clearly state the requirement. Please consider the this rephrasing: "For lines which are neither an element of an IROL nor an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within its Rating and during all Rated Electrical Operating Conditions of the types listed below:..." (remainder is unchanged). 8) On Page 11 of the posted clean draft standard, is the reference to the previous footnote 2 correct? We recommend eliminating footnotes where possible to minimize redirections. 9) The Rationale text-box on page 13 of the clean version of FAC-003-3 overlaps some of the text of footnote #6. â€‚â€‚â€‚
Response:		
Dominion	No	Dominion suggests in FAC-003-X; 4.3.1. Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency overall.Dominion suggests in FAC-003-3; 4.3.1. adding station to the following “ Overhead transmission lines that extend

Organization	Yes or No	Question 3 Comment
		greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are" to show consistency as it is written in FAC-003-X 4.3.1.Further, Dominion is concerned that the technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as "approximate line of sign [sic] from a fixed point" and notes that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.
Response:		
Exelon	No	FAC-003 - Exelon supports the one mile length qualifier, but feels that additional clarification is needed to determine the points of demarcation. There are too many differing physical configurations to use a "fence line" as a determination of applicability. Suggest that the tie line length be defined as "from the Generator Step up Transformer GSU to the point of interconnection between the GO and TO owned equipment." Also suggest that the standard define what constitutes a generation station switchyard.
Response:		
Ingleside Cogeneration LP (Occidental Chemical)	No	Ingleside Cogeneration LP is very concerned that the attempt to develop "bright-line" criteria to assign applicability to either version of FAC-003 is misplaced. As seen with NERC's recent proposed directive related to Generator-Transmission interconnections, those thresholds can be arbitrarily reduced based upon regulators aversion to risk - not scientific evidence. (As it stands today, NERC has proposed any interconnection facility operating at 100 kV or higher and greater than 3 spans in length be applicable - which is even stricter than the TO thresholds in FAC-003.)This would suggest that a reliability assessment consistent with the TPL standards must

Organization	Yes or No	Question 3 Comment
		be the determining factor. If the Planning Coordinator or Transmission Planner can show that the Generator-Transmission interconnection could contribute to a violation of an SOL or IROL, then a vegetation management program may be in order.Furthermore, there needs to be some level of common sense applied if a GO-TO interconnection is located in an area where vegetation clearance is never an issue. A one-size-fits-all requirement based upon vegetation growth in the sub-tropics, should not automatically apply in the desert. In our view, every dollar spent to control vegetation in an arid climate is one less dollar available to purchase advanced telemetry, AGC systems, and other items which have a far greater impact on reliability.
Response:		
Manitoba Hydro	No	Manitoba Hydro does not support the changes being proposed in this project. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions.
Response:		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	No	Suggest in FAC-003-X; 4.3.1. that Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency.In FAC-003-3; 4.3.1. add station to the following: " Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are" to show consistency as it is written in FAC-003-X 4.3.1.The technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as "approximate line of sight [sic] from a fixed point" and noted that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile

Organization	Yes or No	Question 3 Comment
		exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.
Response:		
MRO NSRF	No	The NSRF agrees with the drafting committees desire to eliminate arbitrary and capricious behavior of auditors and industry staff by precisely defining the point at which measurement starts for the length of transmission line. The concern the NSRF has with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would

Organization	Yes or No	Question 3 Comment
		be observed and correct as a matter of routine maintenance. Line of Sight: NSRF recommends a two kilometer distance from the controlled area perimeter. Our assessment is that an individual of average height would have a line of site of approximately 4 Kilometers. Therefore, we recommended a distance of 2 kilometers from the Controlled Area of the plant to provide margin. The revised applicability statement would read as follows: "Generator Owner that owns an overhead transmission line(s) that extends greater than 2.0 kilometers beyond the Controlled Area of the generating station up to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region. Furthermore we applaud the committee for using the metric system to identify the acceptable distance for this standard and urge it to remove all references to English units. We strongly suggest this drafting team and all future drafting team abandon the anachronistic English measurement system. This archaic system, based on the length of an average barley corn, should be abandon in all scientific and engineering endeavors.
Response:		
Southwest Power Pool Standards Development Team	No	There is a possibility of some conflict with the Bulk Electric System Definition. This should be consistent with the Transmission Owner requirements if the lead is determined part of the BES.
Response:		
South Carolina Electric and Gas	No	There should be no qualifying exemption to FAC-003 for Generator Owners.
Response:		

Organization	Yes or No	Question 3 Comment
SERC Planning Standards Subcommittee	No	We believe there should be no exemption for Generator Owners.
Response:		
PSEG	No	
Infigen Energy US	Affirmative	Infigen finds the DST supporting details regarding FAC-003-X to be appropriate. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
Response:		
Seattle City Light	Affirmative	Key points are the greater than one mile with clear statement of "...beyond the fenced area of the generating switchyard."
Response:		
RES Americas Development / American Wind Energy Association	Yes	Applying the vegetation management requirements to only generator lead lines that extend more than "one mile beyond the fenced area of the generating station switchyard" strikes a reasonable balance among the many stakeholder positions expressed on this topic. We think that as this criterion recognizes that there is little need for a vegetation management plan for shorter lines, it should explicitly state that this is true for all such facilities with lines of that length or smaller.
Response:		
Texas Reliability Entity	Yes	In the description of the "second effective date" in FAC-003-X there is an erroneous reference to "Requirement R3," which should be corrected to "Requirement R1."

Organization	Yes or No	Question 3 Comment
Response:		
Seattle City Light	Yes	Key points are the greater than one mile with clear statement of "...beyond the fenced area of the generating switchyard."
Response:		
ACES Power Marketing Standards Collaborators	Yes	We support the changes to FAC-003 suggested by the drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs.
Response:		
SERC OC Standards Review Group	Yes	

Organization	Yes or No	Question 3 Comment
Southwest Power Pool Regional Entity	Yes	
Florida Municipal Power Agency	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	

Organization	Yes or No	Question 3 Comment
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabiltiyFirst		
Tennessee Valley Authority		

4. **Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X?**

Summary Consideration:

Organization	Yes or No	Question 4 Comment
Ameren Services	Negative	The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years.
Response:		

Organization	Yes or No	Question 4 Comment
Texas Reliability Entity	No	A compliance timeframe for the applicable GOs of two years is too long and the scenario used as a basis provides no timing specifics or details. Moreover, the 12 months for an existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard is arguably the same situation as an applicable GO but the applicable GO has an additional 12 months to come into compliance.
Response:		
Ingleside Cogeneration LP (Occidental Chemical)	No	Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify when the first vegetation management inspection quarterly report, and any other requirement with an assigned interval in FAC-003-3 or FAC-003-X. Even if the decision is to adopt the same criteria proposed in CAN-0012, the industry is better served with a clear distinction made up front.
Response:		
PSEG	No	It's no longer applicable.
Response:		
Manitoba Hydro	No	See question 3 comments.
Response:		
Southwest Power Pool Standards Development Team	No	The effective dates should be consistent with the original standard. If there is a reason for the extension we would like to know why.
Response:		

Organization	Yes or No	Question 4 Comment
Southern Company	Yes	â€‚The development of a working TVMP will take some time to initialize. The 1 year time frame for R3 is appropriate. The 2 year time frame for all other requirements is appropriate. â€‚â€‚
Response:		
Seattle City Light	Yes	The explanation deals with the fact that there are simultaneous revisions of FAC-003 underway by two different teams.
Response:		
MRO NSRF	Yes	There may be a typographical error on the effective date. As currently drafted the standard states:In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption. Should it be worded as follows?In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.
Response:		
RES Americas Development/	Yes	Yes, as with our comments to question 2, since there is no exigent reason why this

Organization	Yes or No	Question 4 Comment
American Wind Energy Association		standard needs to be put in place at once, we support the proposed compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.
Response:		
SERC OC Standards Review Group	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply	Yes	

Organization	Yes or No	Question 4 Comment
Association		
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	

Organization	Yes or No	Question 4 Comment
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabiltiyFirst		
Tennessee Valley Authority		

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here.

Summary Consideration:

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	No	See question 3 comments.
Response:		

Organization	Yes or No	Question 5 Comment
Southern Company	No	We believe that a standard development process should not have parallel paths where the same version is being modified by multiple teams. The uncertainty in which development path leads to confusion in the industry and ultimately proves to have wasted come resources for the path that does not come to fruition.
Response:		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration agrees that the SDT's approach is thorough. We are far more concerned about FAC-003's applicability criteria and implementation time frame at this point - as stated in our responses to questions 3 and 4.
Response:		
ACES Power Marketing Standards Collaborators	Yes	With recent NERC BOT approval of the FAC-003-2 standard, the drafting team should continue to monitor the standard progress with FERC and make necessary adjustments to the implementation plan.
Response:		
Ameren		(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance. (b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick

Organization	Yes or No	Question 5 Comment
		sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance. (c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years
Response:		
PSEG	Yes	
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	

Organization	Yes or No	Question 5 Comment
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Wind Energy Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 5 Comment
RES Americas Development	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Texas Reliability Entity	Yes	
Constellation Power Source Generation	Yes	
Tennessee Valley Authority	Yes	
Southwest Power Pool Regional Entity		
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		

Organization	Yes or No	Question 5 Comment
Consolidated Edison Co. of NY, Inc.		
ReliabiltiyFirst		

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group's original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here.

Summary Consideration:

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner's radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term "Facility" is used. Moreover, the Technical Justification document's reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC's registration of GOs as TOs.
Response:		
Texas Reliability Entity	No	Our negative votes on FAC-003 reflect our concern that this project has not considered all of the applicable standards. Why did the SDT choose to only review the Ad Hoc Group's standards when there have been multiple registration appeals in which FERC and NERC have repeatedly cited specific additional TO/TOP standards that were determined to be applicable to GO/GOPs? This SDT project would serve a tremendous value to the ERO and in particular industry if it were to address the technical aspects of the following FERC ordered applicable standards: PRC-001-1 R2, R4; PRC-004-1 R1; TOP-004-2 R6; PER-003-1 R1; FAC-003-1 R1, R2; TOP-001-1a R1 and FAC-004-2 R2. The SDT team should analyze the FERC orders, the applicable standards indicated, and the circumstances and facts involved, and technically justify why no reliability gap exists if these standards are not applied to GO interface facilities.The SDT should include more "technical" information in its technical justification document. For example, in regards to TOP-004-2 R7, the SDT technical justification states that there is no reliability gap because, ". . . because an operator has a fiduciary obligation to protect a Facility for which it is operationally

Organization	Yes or No	Question 6 Comment
		responsible." An entity having a fiduciary obligation is not a technical justification of why a reliability gap does not exist. Moreover, by that logic there would be no need for many standards because every registered entity has a fiduciary obligation to protect its facilities.
Response:		
PSEG	No	PRC-005-1 - Transmission and Generation Protection System Maintenance and Testing was recommended by the Ad Hoc Group for modification, but not addressed to the technical justification document. It should be.
Response:		
Florida Municipal Power Agency	No	see comment to Question 7
Response:		
Manitoba Hydro	No	See Question 7 comments.
Response:		
MRO NSRF	No	The NSRF has one concern with the current justification and definitions. At some point, if enough interconnections are made to generator outlet leads in accordance with FAC-001, the original generator operator will be a Transmission Operator and a Transmission Owner. This point in time needs to be explicitly defined by the drafting team.
Response:		

Organization	Yes or No	Question 6 Comment
Manitoba Hydro		If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: 'the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.' Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, 'interconnection requests for Generator Owner Facilities are still relatively rare.

Organization	Yes or No	Question 6 Comment
Response:		
Electric Power Supply Association	Affirmative	All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.
Response:		
Infigen Energy US	Affirmative	Infigen supports the FAC-001-1 technical analysis by the Project 2010-07 SDT, which states in part that “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply”. We agree with the SDT’s reasoning that if the owner of the existing generator interconnection Facility agrees, or is compelled to allow a third party to interconnect, but can do so using existing agreements, contracts, and/or tariffs [to avoid requiring additional executed Agreement(s)], this is the most prudent

Organization	Yes or No	Question 6 Comment
		and effective way to manage this process with continuity. In order to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility more expediently, it can avoid having to develop its own connection requirements or perform additional impact studies, to the extent possible. We find it reasonable to negotiate with the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider to manage this requirement, utilizing their existing processes and Agreements for the purpose of fulfilling FAC-001-1.
Response:		
Southern Company	Yes	Additional responses are needed to justify the exclusion of the list of requirements and standards found in the recent FERC order denying the rehearing request of the Compliance Registry Appeals of Cedar Creek and Milford. (135 FERC Para. 61,241). Please see our response to Question 10 for a detailed discussion on this topic.â€‚â€‚â€‚
Response:		
Constellation Power Source Generation	Yes	Constellation supports the SDT justifications and offers additional information in our response to question 10.
Response:		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration LP believes the SDT has spent a significant amount of time and effort to demonstrate that only FAC-001, FAC-003, and PRC-004 need to be modified to address any reliability gaps that may exist related to the GO-TO interconnection. We agree that the other standards/requirements identified by the Ad Hoc Group are covered elsewhere.
Response:		

Organization	Yes or No	Question 6 Comment
American Wind Energy Association	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
Response:		
RES Americas Development	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
Response:		
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	

Organization	Yes or No	Question 6 Comment
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 6 Comment
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		
Independent Electricity System Operator		
Ameren		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		

Organization	Yes or No	Question 6 Comment
ReliabiltiyFirst		
Tennessee Valley Authority		

7. **The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards, both to close reliability gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal?**

Summary Consideration:

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Negative	Manitoba Hydro has the following comments: 1) The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner's radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term "Facility" is used. Moreover, the Technical Justification document's reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC's registration of GOs as TOs. 2) Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs 'interconnection facilities' If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, 'interconnection requests for Generator Owner Facilities are still relatively rare.
Response:		

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Negative	Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs 'interconnection facilities' If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, 'interconnection requests for Generator Owner Facilities are still relatively rare.
Response:		
PSEG	No	It would be helpful if the SDT defined what it means by the term "radial generator interconnection Facilities." Does it mean interconnection Facilities that under Normal Clearing for a fault do not interrupt flows on other BES Elements? This is also confusing because of the radial exclusion included in the BES definition work in Project 2010-17. That definition would allow part of a three-terminal circuit to be excluded from the BES, while the other parts are included in the BES.
Response:		
Texas Reliability Entity	No	See comment 6.
Response:		
Manitoba Hydro	No	The SDT's proposed modifications gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001, FAC-003 and PRC-004), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Registry Criteria defines the various functional entities.

Organization	Yes or No	Question 7 Comment
		If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, 'interconnection requests for Generator Owner Facilities are still relatively rare.
Response:		
Southwest Power Pool Regional Entity	No	The Technical Justification document did not review the standards FERC identified in paragraphs 71 and 87 of 135 FERC Â¶ 61,241 ORDER DENYING APPEALS OF ELECTRIC RELIABILITY ORGANIZATION REGISTRATION DETERMINATIONS. The SDT needs to review these standards to determine if changes are needed; otherwise, FERC will require registration of GOs and GOPs as TOs and TOPs to address reliability gaps. If the SDT determines no changes are needed to these FERC-identified standards, they should provide justification.
Response:		
Southern Company	No	We don't believe the effort realizes the goal because 1) it is inclusive of FAC-001 that does not need any modifications and 2) the effort needs to reinforce the appropriate justification not to include the additional standards FERC has identified in their Cedar Creek and Milford Orders.
Response:		
Western Electricity Coordinating Council	No	WECC casts an affirmative vote for the SDT proposal as a necessary but not sufficient step in addressing the GOTO matter. WECC, NERC, and the other Regions developed

Organization	Yes or No	Question 7 Comment
		a subset of Standards and Requirements that were considered necessary to address potential gaps for transmission interconnection facilities and operations to be included in a proposed NERC Directive, which is expected to issue by year-end. The subset of requirements developed for the proposed NERC Directive were informed by the applicable FERC Orders. Consequently, it is important that the SDT address the comparative reliability risks between the proposed NERC Directive List and the SDT Proposal to assure that reliability gaps will not result from the SDT proposal. Please see NERC's proposed Directive for the rationale and technical justification.
Response:		
Florida Municipal Power Agency		FMPA believes that TOP-004-2 R6.2 ought to also be addressed in the standards as applicable to GOPs. The requirements reads:R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:R6.2. Switching transmission elements.Although planned outages are covered in other standards applicable to a GOP, switching to close / synchronize a generator back to the system is not specifically covered in the standards. Some have argued that TOP-002-2 R3 causes GOPs to coordinate its current day plans with the TOP; however, the name of the standard is "Transmission Operations Planning" and therefore implies the availability of the generator and related equipment and not necessary implies the policies and procedures for switching operations; which includes synchronization. FMPA cannot imagine a generator that would not have such switching / synchronization policies and procedures coordinated with its interconnecting TOP; as such would normally be required through a Large Generator Interconnection Agreement through a pro forma OATT; however, FMPA is not aware of any instance in the standards that covers this. As such, FMPA recommends including TOP-004-2 R6.2 as being applicable to a GOP.

Organization	Yes or No	Question 7 Comment
Response:		
Manitoba Hydro		If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.
Response:		
SERC OC Standards Review Group		Please list the set of standards are you referencing.
Response:		
Constellation Power Source Generation, Inc.	Affirmative	Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. Please see more detailed comments submitted in the Project 2010-07 comment form submitted on November 18, 2011.
Response:		
Infigen Energy US	Affirmative	Infigen finds the SDT supporting measures and analysis regarding FAC-003-3 to be

Organization	Yes or No	Question 7 Comment
		appropriate, and believes that it is prudent for Generation Owners and Transmission Owners to manage vegetation maintenance records/inspections accordingly. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
Response:		
PPL EnergyPlus LLC	Affirmative	PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
Response:		
Puget Sound Energy, Inc.	Affirmative	The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
Response:		

Organization	Yes or No	Question 7 Comment
Southwest Transmission Cooperative, Inc. / ACES Power Marketing	Affirmative	We largely support the changes made by drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs. Subjecting a GO/GOP to any TO/TOP standards requirements should require a clear demonstration f the reliability gap in each instance. Some additional changes are necessary to FAC-001.
Response:		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Although the SDT is nearing conclusion on the closing of reliability gaps, the unnecessary registration of GOs and GOPs as TOs and TOPs is far from resolved in our view. Ingleside Cogeneration's concern is based upon NERC's recent proposal to dictate an interim GO-TO interconnection solution which completely bypasses the Standards Development Process. Frankly, it seriously brings to question the nature of the consensus-driven process - which appears to be moving in a dictatorial direction.
Response:		

Organization	Yes or No	Question 7 Comment
American Wind Energy Association	Yes	AWEA believes that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.
Response:		
RES Americas Development	Yes	We believe that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.
Response:		
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power	Yes	

Organization	Yes or No	Question 7 Comment
Coordinating Council		
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 7 Comment
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		
South Carolina Electric and Gas		
Consolidated Edison Co. of NY, Inc.		

Organization	Yes or No	Question 7 Comment
Entergy Services		
ReliabiltiyFirst		
Tennessee Valley Authority		

8. If you answered "yes" to Question 7, are the modifications the SDT has made in this posting the appropriate ones?

Summary Consideration:

Organization	Yes or No	Question 8 Comment
Ameren	No	Please refre to our comments in reposnes to #3, #4, and #5 above.
Response:		
Texas Reliability Entity	No	See comment 6.
Response:		
Ingleside Cogeneration LP (Occidental Chemical)	No	See comments to questions 1 through 4.

Organization	Yes or No	Question 8 Comment
Response:		
SERC Planning Standards Subcommittee	No	See our comments above for question # 3.
Response:		
South Carolina Electric and Gas	No	The modifications are appropriate with the exception noted in question #3.
Response:		
ACES Power Marketing Standards Collaborators	No	The modifications are largely the appropriate ones with the exceptions we noted in Q1 and Q10.
Response:		
Southwest Power Pool Standards Development Team	No	We agree that the standards being addressed are correct. See above comments. There are some issues with the determination of which facilities are deemed BES since ownership of what may be a BES facility may not always be by a Transmission Owner. All relevant standards should apply to BES facilities regardless of ownership.
Response:		
PSEG	No	
Response:		
SERC OC Standards Review Group		See comments on Question 7. If the standards referenced in question 7 are FAC-001, FAC-003 and PRC-004, we would answer yes to this question.

Organization	Yes or No	Question 8 Comment
Response:		
Southern Company	Yes	â€,The version history table is incorrect - change version 3 to version 2.1.â€,â€,
Response:		
RES Americas Development/ American Wind Energy Association	Yes	For the most, we agree that the SDT proposal strikes a reasonable balance and provides the requisite level of clarity and certainty necessary for GO/GOPs to understand their responsibilities and compliance requirements.
Response:		
MRO NSRF	Yes	The NSRF agrees if the drafting team incorporates as suggested improvements
Response:		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North	Yes	

Organization	Yes or No	Question 8 Comment
America Inc.		
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Southwest Power Pool Regional Entity		
Florida Municipal Power		

Organization	Yes or No	Question 8 Comment
Agency		
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		
Manitoba Hydro		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabiltiyFirst		
Tennessee Valley Authority		

9. **If you answered "no" to Question 7, what standards need to be added or removed to achieve the SDT's goal? Please provide technical justification for your answer.**

Summary Consideration:

Organization	Yes or No	Question 9 Comment
Cowlitz County PUD	No	N/A
Manitoba Hydro	No	See question 7 comments.
Response:		
Southern Company	Yes	â€, Southern does not think that the revision to FAC-001-1 is necessary. A Generator

Organization	Yes or No	Question 9 Comment
		Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System (i.e., the “interconnected TO” or “interconnected TP”). A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO’s Facility connection requirements whether the GO wants to connect additional facilities or a third parties’ facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO or interconnected TP that has connection requirements that must be fulfilled. The GO’s Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected TO or interconnected TP. A GO should not need to develop “connection requirements” unless it is in the business of owning and operating facilities independently of its interconnected TO or interconnected TP. We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner’s function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource White Paper acknowledges that this may be necessary: “The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner.” [Arguments related to jurisdictional, interconnection policy and open access

Organization	Yes or No	Question 9 Comment
		transmission tariff issues](1) Because of (a) jurisdiction under Section 215, (b) FERC's interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO's generating Facility reaches commercial operation. NERC should not make facilities subject to the mandatory reliability standards before the facilities are actually part of the BES.(a) Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the "Electric Reliability Organization" as "the organization certified by the Commission ... the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review." Further, (a)(3) provides that "The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ...." Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached "commercial operation") and for the design of planned additions or modifications. It is logical to interpret the phrase "design of new facilities" as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction. (b) FERC's interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC

Organization	Yes or No	Question 9 Comment
		was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised FAC-001 would appear to restrict some of this flexibility.(i) Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration. (ii) The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard? (iii) FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer's identity in contravention of the requirements in Order No. 2003 and the LGIP.(c) OATT requirements. The definition of “applicable Generator Owner” (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO’s existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate

Organization	Yes or No	Question 9 Comment
		the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement (with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard. (2) The following are suggested changes to FAC-001-1. (a) We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..." (b) It is unclear in Applicability section 4.2.1 that the term "Agreement" means that the GO has an executed agreement with a TO/TSP or that the GO and the third party have an executed agreement. Without further explanation, the capitalized term "Agreement" has the effect of introducing confusion. If the SDT does not intend to propose a new addition to the NERC Glossary of Terms, it should use the lower case term, "agreement." With respect to the capitalized term, "Transmission System," the SDT should consider clarifying if it intends to propose adding this to the Glossary. (3) Effect of the proposed revisions to FAC-001-1 on FAC-002-1.(a) As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002. (b) FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any

Organization	Yes or No	Question 9 Comment
		interconnection with the appropriate Transmission Provider, TP and PA.
Response:		
PSEG	Yes	We believe that the Ad Hoc Group's suggestions regarding PRC-005-1 - Transmission and Generation Protection System Maintenance were correct and that this standard should have been modified by the SDT in a manner similar to the way the SDT modified PRC-004-2. This would require modifying R1 and R2 in PRC-005-1a (the current version) to include protection systems in the generator interconnection Facility. In addition, the SDT should evaluate modifying PER-002-0 - Operation Personnel Training. In doing so the SDT completes one of the open FERC directives in Order 693. Paragraph 1363 addresses GOP training:1363. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.
Response:		
Ingleside Cogeneration LP (Occidental Chemical)		Ingleside Cogeneration LP believes that the set of standards proposed by the SDT is technologically accurate and defensible. The open issue is if the ERO and FERC expect more standards to be included - whether based upon sound reliability principals or not.

Organization	Yes or No	Question 9 Comment
Response:		
Western Electricity Coordinating Council		PLease see response to question #7.
Response:		
Texas Reliability Entity		See comment 6.
Response:		
SERC OC Standards Review Group		See comments on Questions 7 & 8.
Response:		
Florida Municipal Power Agency		see response to Question 7
Manitoba Hydro		The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not be required.
Response:		

Organization	Yes or No	Question 9 Comment
Southwest Power Pool Regional Entity		The SDT should consider the standards that FERC identified in 135 FERC Â¶ 61,241.
Response:		
Southwest Power Pool Standards Development Team		
Northeast Power Coordinating Council, Northeast Power Coordinating Council		
MRO NSRF		
SERC Planning Standards Subcommittee		
Dominion		
PPL NERC Registered Affiliates		
ACES Power Marketing Standards Collaborators		
Electric Power Supply Association		
American Wind Energy Association		

Organization	Yes or No	Question 9 Comment
Puget Sound Energy, Inc.		
Compliance & Responsbility Organization		
Bonneville Power Administration		
American Electric Power		
BP Wind Energy North America Inc.		
Exelon		
Seattle City Light		
Independent Electricity System Operator		
Duke Energy		
Oncor Electric Delivery Company LLC		
Ameren		
American Transmission Company		

Organization	Yes or No	Question 9 Comment
South Carolina Electric and Gas		
RES Americas Development		
Sempra Generation		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
Xcel Energy		
ReliabiltiyFirst		
Constellation Power Source Generation		
Tennessee Valley Authority		

10. Do you have any other comments that you have not yet addressed? If yes, please explain.

Summary Consideration:

Organization	Yes or No	Question 10 Comment
Gainesville Regional Utilities	Negative	1. It would seem that the impetus for FAC003 is to eliminate vegetation related outages within the rights-of-way as defined and subject to the exclusions as stated in footnote 2. Thus the requirement is to manage the ROW to prevent vegetation related sustained outages with the measure being no outages. With grow-ins and fall-ins from within the defined ROW being controllable factors. 2. Including encroachments leaves the door open for fines to be imposed with no actual outage(s) having occurred. This may be like being found guilty of a crime that has not yet taken place. 3. Combine vegetation related sustained outages by “grow-ins” and “blowing together of lines and vegetation located inside the ROW” as one item as they are both consequences of the growth of vegetation either vertically and horizontally. 4. Leave vegetation related sustained outages by “fall-in” as a standalone as this will be related to structural problems occurring from a variety of sources. 5. Combine R3 and R7 to R1 (development and implementation of a Transmission Vegetation Management Plan which shall include documented maintenance strategies or procedures or processes or specifications, delineation of an annual work plan and completion of same). Thus this would be the competency based requirements as a program without execution is meaningless. 6. R1 and R2 become R2 and R3.
Response:		
Northern Indiana Public Service Co.	Negative	Ballot needs work
Response:		
PSEG Energy Resources & Trade LLC, PSEG Fossil LLC,	Negative	FAC-003-X is not applicable since FAC-003-2 was approved by the BOT on November 4, 2011

Organization	Yes or No	Question 10 Comment
Public Service Electric and Gas Co.		
Response:		
Hydro-Quebec TransEnergie	Negative	Hydro-Quebec TransEnergie is casting a negative vote again because our comment from the last posting was not considered in the current draft: The minimum frequency of Vegetation Inspection should be based upon an average growth rates of smaller regions than all North America. Example, above the latitude of 50 degrees North, the vegetation growth rates is limited. The Vegetation Inspection frequency in the territories located above 50 degrees of latitude must be relaxed to 3 years.
Response:		
New Brunswick System Operator	Negative	Since NBSO voted 'affirmative' for FAC-003-3, it makes sense for us to vote 'negative' for this standard.
Response:		
PSEG Energy Resources & Trade LLC/ Public Service Electric and Gas Co./ PSEG Fossil LLC	Negative	The phrase “generator Facility” should be “generator Transmission Facility,” and the phrase “Transmission System” should be “Transmission system.”
Response:		
SERC Reliability Corporation	Negative	There should not be a weak link under the standard. This proposed revision would create a weak-link where a portion of the otherwise covered right-of-way would be exposed.

Organization	Yes or No	Question 10 Comment
Response:		
New York State Department of Public Service/ National Association of Regulatory Utility Commissioners	Negative	Understand that there is an open issue regarding the availablility of generation compliance documentation that needs to be satisfactorily addressed.
Response:		
Infigen Energy US	Affirmative	Infigen supports the efforts of the SDT to ensure that Protection System Misoperations affecting the reliability of the BES are thoroughly analyzed and mitigated. Generator Owners are already analyzing Misoperations as/if they occur, and are employing Corrective Action Plans to avoid future Misoperations. We support maintaining "reasonable and appropriate" preventative measures and risk assessment tools to ensure that misoperations are evaluated and corrected expediently.
Response:		
PPL EnergyPlus LLC/PPL NERC Registered Affiliates	Affirmative	PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
Response:		

Organization	Yes or No	Question 10 Comment
SERC Reliability Corporation	Affirmative	The Generator Owner may be required to self-certify and report periodically to the region whether they have become applicable to the standard.
Response:		
Southwest Transmission Cooperative, Inc./ ACES Power Marketing Standards Collaborators/ ACES Power Marketing	Affirmative	The modifications to PRC-004-2.1 R2 could be interpreted as requiring the GO to analyze Protection System Misoperations on the generator interconnection Facility even if it does not own the Facility. We suggest modifying the requirement as shown below to address this issue."The Generator Owner shall analyze Protection System Misoperations on its generator and generator interconnection Facility that it owns ..."
Response:		
SERC Reliability Corporation	Affirmative	With the understanding the Generator Interconnection FAcilities will be grouped with Transmission Protection Systems for analysis at the regional level.
Response:		
Entergy Services		We suggest that the Vegetation Management Standards should be consistent for both the TO and GO facilities. We would also like to suggest an additional Recommendation for added clarity regarding Category 3 Outages (Off-ROW Fall-in Outages). We understand that the Category 3 Outages are not a violation of the Standard, but we feel that there should be some level of comment added within the Standard clearly stating that these Outages are "Reportable Only" during the Quarterly Outage reports to the RE's, and that there are no associated violations/sanctions for this Category Of Outage, and that an Off-ROW fall-in outage would not be considered an encroachment into the MVCD in any way. The Technical Reference Document does a good job of clearly stating this in the Introduction on Page 5 ("This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human

Organization	Yes or No	Question 10 Comment
		activities or acts of nature.") and we feel that this should also be stated clearly in the Standard.
Response:		
Southern Company		We agree with the 2010-17 Standard Drafting Team's conclusion to not modify other standards such as those mentioned on page 4 of the Technical Justification document. In additon, we wish to provide the following support for exclusion of these specific standards. Southern Company believes NERC's Project 2010-07 SDT must challenge making revisions to the standards included in the FERC order on Cedar Creek and Milford. (This order supports NERC's requirement for those entities to register as a TO/TOP due to their ownership of generator interconnection circuits > 100kV.) We believe there are clear technical and reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. Furthermore, we also believe there are clear distinctions between GO/GOP responsibilities and TO/TOP responsibilities that must be maintained to ensure BES reliability. Revising standards to assign TO/TOP responsibilities to a GO/GOP or requiring a GO/GOP to register as a TO/TOP because of generator interconnection circuits > 100kV will reduce the clarity of these responsibilities. We have provided specific comments on each standard below: EOP-005-1 R1, R2, R6, R7R1 and R2 require each TOP to have and maintain a system restoration plan. R6 requires the TOP to train its operating personnel in implementing this plan. R7 requires the TOP to verify its restoration plan by actual testing or simulation. These requirements are clearly the role and responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP's control area. The GOP's roles and responsibilities are clearly and appropriately addressed EOP-005-2. The presence of a generator interconnection circuit > 100kV that happens to be owned by the GO instead of the TOP fundamentally does not change the roles and responsibilities of the TOP or the GOP. Thus, no changes due to EOP-005 are needed.FAC-014-2, R2FAC-014-2 R2 states "The

Organization	Yes or No	Question 10 Comment
		Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." FAC-014-2 R2 should not be revised to include GOPs. The GO is required by FAC-008-1 R1 and FAC-009-1 (FERC approved version) and pending FAC-008-3 R3 and R6 (FAC-008-3 filed with FERC for approval) to document the Facility Ratings for a GO-owned generator interconnection circuit >100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the GO to the GOP if they are not the same entity. The operating voltage limits for this circuit are established by the applicable TO/TOP, not the GO or GOP. Therefore, we believe adding the GO to FAC-014-2 R2 would be redundant.PER-003-1 R2, R2.1, R2.2PER-003-1 R2 and its sub-requirements state:"R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates (1) : [Risk Factor: High][Time Horizon: Real-time Operations]: R2.1. Areas of Competency R2.1.1. Transmission operations R2.1.2. Emergency preparedness and operations R2.1.3. System operations R2.1.4. Protection and control R2.1.5. Voltage and reactive R2.2. Certificates o Reliability Operator o Balancing, Interchange and Transmission Operator o Transmission Operator This requirement is specifically for TOPs. Personnel training for GOPs needs to be addressed separately and not mingled with responsibilities of the TOP. The GOPs role in supporting BES reliability needs to be clearly understood and defined prior to establishing training requirements in the standards. PRC-001-1, R2, R2.2, R4, R6Generator Operators (GOPs) and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2 The language used in requirement R2 which applies to the GOP uses the general terms "relay or equipment failures" which would include not only generator relaying,

Organization	Yes or No	Question 10 Comment
		but generator interconnection relaying in the GOPs scope as well. The GOP is required to notify the TOP and Host BA in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected TOP to notify its RC and affected TOPs and BAs. Thus, applying R2.2 to a GOP would be redundant to R2.1. Requirement R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.” A generator interconnection tie line does not constitute a ‘major tie line” or major “interconnection with neighboring GOPs, TOPs, and BAs.” Thus, R4 should not be revised to include GOPs. If a GO exists within NERC that does own such interconnection facilities, the responsibility for coordination of protection systems on such a line or interconnection should be the responsibility of the TOP in that area, not the GO/GOP. This may require formal agreements between the TO/TOP and GO/GOP, since the GO may own protection equipment on his end. The same logic applies to R6. R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” This is clearly the responsibility of the TOP and/or BA, not a GO/GOP who happens to have generator interconnection facilities in the area. An SPS function by definition is to maintain BES reliability. If a GO/GOP has equipment within the equipment scope of a Special Protection System (SPS), responsibility for monitoring the SPS should be conveyed in a formal agreement as appropriate. TOP-001-1 R1Requirement R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” This is clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, R1 should not be applied to a GO/GOP who owns or operates generator interconnection facilities. Furthermore, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) appropriately requires the GOP to comply with reliability directives issued by

Organization	Yes or No	Question 10 Comment
		the TO “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment. Thus, no changes to TOP-001-1 are necessary. TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:R6.1. Monitoring and controlling voltage levels and real and reactive power flows.R6.2. Switching transmission elements.R6.3. Planned outages of transmission elements.R6.4. Responding to IROL and SOL violations.”These are clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, these requirements should not be applied to a GO/GOP who owns or operates generator interconnection facilities. The same logic applies here as stated above in our discussion on TOP-001-1. We believe it is inappropriate and would be adverse to BES reliability to apply these requirements to a GOP. TOP-004-2 effectively gives the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment, such as opening high voltage generator output breakers when required to protect the unit. Thus, no changes to TOP-004-2 are necessary.TOP-006-2 R3Requirement R3 states, “R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel. The intent of this requirement when applied to a GOP is already addressed in PRC-001-1 R1 which states, “Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.” Thus, no change to TOP-006-2 is necessary.

Organization	Yes or No	Question 10 Comment
		â€‚â€‚
Response:		
American Wind Energy Association		AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT's approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.
Response:		
Bonneville Power		BPA thanks you for the opportunity to comment on Project 2010-07, Generator

Organization	Yes or No	Question 10 Comment
Administration		Requirements at the Transmission Interface. BPA stands in support of the proposed revisions and has no comments or concerns at this time.
Response:		
Constellation Power Source Generation		Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised.While the revision process focuses on specific standards, it is important to consider the reliability questions in the context of the full complement of reliability standards that apply to entities. For instance, the following standards already apply to generators and relate to the reliability considerations around transmission at the generator interface: o PRC-001-1 addresses coordination of protection system components by requiring all GOs to ensure coordination of their protection system with interconnected parties. Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc. o PRC-004-1 requires all GOs to ensure that they analyze all misoperations on their protection system which would include the protection of the tie line. o TOP standards applicable to GOs aid coordination between a GO and a TO with regards to the generator tie line by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs. o RC, TOP and/or BA certified operators control and are responsible for overseeing that transmission. According to the NERC functional model, a Generator Operator is defined as “operat(ing) generating unit(s) and perform(ing) the functions of supplying energy and reliability related services.” Given this limited scope, the Generator Operator (GOP) cannot be considered as operating on the same level as the Reliability Coordinator, Transmission Operator or Balancing Authority when it comes to real time information on the status of the BES. The GOP does not monitor

Organization	Yes or No	Question 10 Comment
		and control the BES, rather the GOP only monitors and controls the generators that it operates and relays information to other operating entities. o IRO and TOP standards applicable to GOs include tie lines in their pool of resources to alleviate operational emergencies by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance. o FAC-8 and FAC-9 manage rating methodology consistency by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator's profits are directly tied to its output. Therefore no generator would limit its facility to the equipment that is delivering that output.
Response:		
Cowlitz County PUD		In answer to the SDT request for feedback on FERC's Order concerning Cedar Creek and Milford, the District finds no technical reason to add any of the listed standard requirements, and struggles to understand why FERC would even consider this listing as applicable.
Response:		
Southwest Transmission Cooperative, Inc.		In section 4.2.1 of the Applicability Section, "within" should be "with". Because NERC's Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to "once required by Requirement R2". This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.

Organization	Yes or No	Question 10 Comment
Response:		
Manitoba Hydro		Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.
Response:		
Compliance & Responsbility Organization		NextEra Energy, Inc. (NextEra) appreciates the work of the Project 2010-07 Generator Requirements at the Transmission Interface Standard Drafting Team (SDT) on a subject that NextEra has a significant interest in resolving. In fact, NextEra has been a member of the SDT and an active observer. Given the recent events - such as (a) the North American Electric Reliability Commission's draft interim directive; (b) the denial of the Milford and Cedar Cheek requests for reconsideration at the Federal Energy Regulatory Commission (FERC) and (c) the record in this case which, at times, suggests the SDT needs to more formally consider the Milford and Cedar Cheek Reliability Standards - NextEra requests that SDT more formally consider the merits of each Reliability Standard adopted the Milford and Cedar Cheek FERC orders and the NERC draft interim directive. Although NextEra does not condone the manner in which NERC issued the interim draft directive and stated so in its comments to NERC on the interim draft directive, NextEra's overarching objective on this issue is to bring a uniform, fair and technically supported approach that resolves the interface issue. Thus, NextEra requests that the SDT (prior to proceeding any further or any additional comments or votes on specific draft Reliability Standards) issue a technical paper that point-by-point addresses the merits of including the Reliability Standards set forth in the FERC Orders and NERC's draft interim directive, and request stakeholder, including NERC staff, comment. For example, this technical paper would likely the merits of NERC's draft interim directive not requiring NERC-certified operators (but require training of interface operators), while FERC's orders require NERC-certified operators. While NextEra does not agree five days of training is necessary for an

Organization	Yes or No	Question 10 Comment
		interface operator, as the draft interim directive appears to propose, NextEra does believe a technical case can be made why NERC-certification is not required, and that some degree of training related to the applicable Reliability Standards is reasonable. Similar, on FAC-003 (as well as several other Standards), the draft interim directive proposes a slightly different approach than the SDT. NextEra would rather these approaches reconciled than be in conflict, with the potential for continued conflict as the SDT's work product proceeds. Further, NextEra requests that the SDT's review the technical merits of NERC's proposed criteria to determine what generator transmission lead is required to comply with additional Reliability Standards. As noted, above, this technical paper should be posted for stakeholder, including NERC staff, comment. Accordingly, while NextEra would have preferred that NERC and the Regional Entities express there interim draft directive approach on the record in this proceeding, NextEra believes it is appropriate for the SDT to draft a comprehensive technical paper that, with an open approach, considers the inclusion of additional Reliability Standards, if appropriate, as a way of building lasting support for its approach.
Response:		
Dominion		No
Tennessee Valley Authority		No
Exelon		PRC-004 - suggest that the Standard state that responsibility for the analysis of missoperations of protective equipment shall be the responsibility of the owner of the protective equipment.
Response:		
ReliabiltiyFirst		ReliabilityFist has found a number of editiorial erros for the FAC-001-1 VSLs. They

Organization	Yes or No	Question 10 Comment
		include the following:1. VSL R1 - should not reference sub-requirements, should reference the sub-parts consistent with the requirement (i.e. Requirement R1, Part 1.1, 1.2 or 1.3)2. VSL for R3 - the VSL should referenced Requirement 3, Part 3.1.1 through 3.1.16 rather than what is currently stated (Requirement R3, Part 3.1.1 R3.1.6)
Response:		
RES Americas Development		RES and AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. We support the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. RES and AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT's approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the

Organization	Yes or No	Question 10 Comment
		impact on the reliability of the Bulk Electric System.
Sempra Generation		Sempra Generation also supports the comments, being concurrently filed, of the Electric Power Supply Association (EPSA).
Response:		
Puget Sound Energy, Inc.		The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
Response:		
SERC Planning Standards Subcommittee/ SERC OC Standards Review Group		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"
Response:		
Southwest Power Pool Standards Development Team		
Southwest Power Pool Regional Entity		

Organization	Yes or No	Question 10 Comment
MRO NSRF		
Florida Municipal Power Agency		
Western Electricity Coordinating Council		
Electric Power Supply Association		
American Electric Power		
BP Wind Energy North America Inc.		
Seattle City Light		
Ingleside Cogeneration LP (Occidental Chemical)		
Independent Electricity System Operator		
Duke Energy		
Oncor Electric Delivery Company LLC		
Ameren		

Organization	Yes or No	Question 10 Comment
PSEG		
American Transmission Company		
South Carolina Electric and Gas		
Consolidated Edison Co. of NY, Inc.		
Xcel Energy		
Texas Reliability Entity		

END OF REPORT

A. Introduction

1. Title: **Facility Connection Requirements**

2. Number: FAC-001-~~0~~ 1

3. Purpose: To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.

4. Applicability:

4.1. Transmission Owner

4.2. Applicable Generator Owner

4.2.1 Generator Owner within an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.

5. Effective Date: ~~April 1, 2005~~

5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional ~~Reliability Organization~~Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements. The Transmission Owner's Facility connection requirements shall address connection requirements for:

1.1. Generation Facilities,

1.2. Transmission Facilities, and

1.3. End-user Facilities

[VRF – Medium]

R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission ~~Owner's~~ System (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

[VRF – Medium]

R3. Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address~~, but are not limited to,~~ the following items~~:~~ in its Facility connection requirements:

3.1. Provide a written summary of its plans to achieve the required system performance as described ~~above~~in Requirements R1 or R2 throughout the planning horizon:

3.1.1. Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission Systems.

3.1.2. Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission Systems) as soon as feasible.

3.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.

3.1.4. Breaker duty and surge protection.

3.1.5. System protection and coordination.

3.1.6. Metering and telecommunications.

3.1.7. Grounding and safety issues.

3.1.8. Insulation and insulation coordination.

3.1.9. Voltage, Reactive Power, and power factor control.

3.1.10. Power quality impacts.

3.1.11. Equipment Ratings.

3.1.12. Synchronizing of Facilities.

3.1.13. Maintenance coordination.

3.1.14. Operational issues (abnormal frequency and voltages).

3.1.15. Inspection requirements for existing or new Facilities.

3.1.16. Communications and procedures during normal and emergency operating conditions.

[VRF – Medium]

R4. The Transmission Owner shall maintain and update its Facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional ~~Reliability Organization~~Entity, and ~~NERC~~ERO on request (five business days).

[VRF – Medium]

C. Measures

M1. The Transmission Owner shall make available (to its Compliance ~~Monitor) for inspection~~Enforcement Authority) evidence that it met all the requirements stated in ~~Reliability Standard FAC-001-0~~ Requirement R1.

M2. Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission ~~Owner~~System shall make available (to its Compliance ~~Monitor) for inspection~~Enforcement Authority) evidence that it met all requirements stated in ~~Reliability Standard FAC-001-0~~ Requirement R2.

M3. ~~The~~Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance ~~Monitor) for inspection~~Enforcement Authority) evidence that it met all ~~the~~ requirements stated in ~~Reliability Standard FAC-001-0_R3~~Requirement R3.

~~**M3.**~~**M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Compliance Monitor: Regional ~~Reliability Organization.~~Entity

1.2. Compliance Monitoring ~~Period~~ and ~~Reset Timeframe~~Enforcement Processes:

~~On request (five business days).~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

~~None specified.~~

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels ~~of Non-Compliance~~

~~**2.1. Level 1:** Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard FAC-001-0_R1, but the document(s) do not address all of the requirements of Reliability Standard FAC-001-0_R2.~~

~~**2.2. Level 2:** Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, but the document(s) provided address all of the requirements of Reliability Standard FAC-001-0_R2.~~

~~**2.3. Level 3:** Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, and the document(s) provided do not address all of the requirements of Reliability Standard FAC-001-0_R2.~~

~~**2.4. Level 4:** No document on facility connection requirements was provided per Reliability Standard FAC-001-0_R3.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	The Transmission Owner failed to do one of the following: Document or maintain or publish Facility connection requirements as specified in the Requirement	The Transmission Owner failed to do one of the following: Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3 OR	The Transmission Owner did not develop Facility connection requirements.

		OR Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.	Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement **and** failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.	
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.
R3	The responsible entity's Facility connection requirements failed to address one of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	The responsible entity's Facility connection requirements failed to address two of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	The responsible entity's Facility connection requirements failed to address three of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	The responsible entity's Facility connection requirements failed to address four or more of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

E. **Regional Differences**

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date	Revision under Project 2010-07

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for FAC-001-1 ~~–~~ –
Facility Connection Requirements

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 – Facility Connection Requirements will be retired ~~when~~at midnight the day before FAC-001-1 becomes effective.

Compliance with Standard

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify ~~two~~one existing ~~requirements~~requirement (now R3~~ and R4~~)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

Effective Date

There are two effective dates associated with this standard:

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

~~**Standard Development Timeline**~~
~~*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*~~

Style Definition: List Number: Font: Not Bold, Outline numbered + Level: 3 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.75" + Tab after: 0.85" + Indent at: 1.5"

~~**Development Steps Completed**~~

1. ~~SC approved SAR for initial posting (January 11, 2007).~~
2. ~~SAR posted for comment (January 15–February 14, 2007).~~
3. ~~SAR posted for comment (April 10–May 9, 2007).~~
4. ~~SC authorized moving the SAR forward to standard development (June 27, 2007).~~
5. ~~First draft of proposed standard posted (October 27, 2008-November 25, 2008)).~~
6. ~~Second draft of revised standard posted (September 10, 20-October 24, 2009).~~
7. ~~Third draft of revised standard posted (March 1, 2010-March 31, 2010).~~
8. ~~Fourth draft of revised standard posted (June 17, 2010-July 17, 2010).~~
9. ~~Fifth draft of revised standard posted (February 18, 2011-February 28, 2011)~~
10. ~~Sixth draft of revised standard posted (September xx – 2011)~~

~~**Proposed Action Plan and Description of Current Draft**~~
~~This is the fourth posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the sixth draft overall.~~

~~**Future Development Plan**~~

~~Anticipated Actions~~	~~Anticipated Date~~
~~Recirculation ballot of standards.~~	~~September 2011~~
~~Receive BOT approval~~	~~November 2011~~

Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

> In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

> In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

~~This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.~~

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

Version	Date	Action	Change Tracking
~~1~~	~~TBA~~	~~1. Added "Standard Development Roadmap."~~ ~~2. Changed "60" to "Sixty" in section A, 5.2.~~ ~~3. Added "Proposed Effective Date: April 7, 2006" to footer.~~ ~~4. Added "Draft 3: November 17, 2005" to footer.~~	~~01/20/06~~
~~1~~	~~April 4, 2007~~	~~Regulatory Approval — Effective Date~~	~~New~~
~~2~~3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Right-of-Way (ROW)
The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

Vegetation Inspection
The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Minimum Vegetation Clearance Distance (MVCD)
The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. Several scenarios that could play out based on the order of the approval of these versions of the standards are addressed in the FAC-003-3 implementation plan.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-3~~2~~

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability**

   4.1. Functional Entities:

   4.1.1. Applicable Transmission Owners

   4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

   4.1.2. Applicable Generator Owners

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4.1.2.1. Generator Owners that own generation Facilities defined in 4.3

~~4.1.~~

~~4.1.1 Transmission Owners~~

4.2. **Transmission Facilities:** Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. ~~4.2.1.~~ Each overhead transmission line operated at 200kV or higher.

4.2.2. ~~4.2.2.~~ Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3. ~~4.2.3.~~ Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

4.2.4. ~~4.2.4.~~ Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

Rationale: The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. ~~3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners.~~ ~~3~~4) Specifically

4.3. **Generation Facilities:** Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating switchyard and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

~~Rationale: The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards,~~

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[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

[2] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" are provided for informational purposes. They are designed to convey guidance from NERC's various activities. The "Guideline and Technical Basis" section and text boxes with "Examples" and "Rationale" are not intended to establish new Requirements under NERC's Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" is not a substitute for compliance with Requirements in NERC's Reliability Standards."

5. Background:

5.1.1. This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

5.1.2. a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system* *performance result or outcome*?

5.1.3. b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome* *that reduces a stated risk* *to the reliability of the bulk power system*?

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5.1.4. c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have* *what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system*?

5.1.5. The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

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This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

5.1.6. For this standard, the requirements have been developed as follows:

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5.1.7. Performance-based: Requirements 1 and 2

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5.1.8. Competency-based: Requirement 3

5.1.9. Risk-based: Requirements 4, 5, 6 and 7

5.1.10. R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves

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as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

5.1.11. Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

5.1.12. This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

5.1.13. This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

5.1.14. Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[3] [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[4],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[5],
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of ~~a~~ an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.

3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

M1. Each applicable Transmission Owner

[3] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~a Transmission Owner~~ subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[4] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[5] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner ~~Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage[4]

M2. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

3.1 Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2 Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[*Violation Risk Factor: Lower*] [*Time Horizon: Long Term Planning*]:

Rationale

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner~~Transmission Owner~~, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*].

Rationale

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ and the control center when a critical situation is confirmed.

M4. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner~~Transmission Owner~~ shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

Rationale

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

M5. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

Rationale

Inspections are used by applicable Transmission Owners and applicable Generator Owners~~Transmission Owners~~ to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors

R6. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[6] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

[6] When the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a

M6. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[7]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[7] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

M7. Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

5.1.15. Compliance Audit

5.1.16. Self-Certification

5.1.17. Spot Checking

5.1.18. Compliance Violation Investigation

5.1.19. Self-Reporting

Complaint

Periodic Data Submittal

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1.4 Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner~~Transmission Owner~~.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners~~Transmission Owners~~, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

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Table of Compliance Elements

On November 3, NERC's Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management with NERC staff-proposed changes to the VSLs for R1 and R2 in lieu of the Project 2007-07 SDT's original proposed VSLs. Those latest changes are reflected here in blue. The only additional change made by the Project 2010-07 SDT was to change "Transmission Owner" to "responsible entity."

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	~~The Transmission Ownerresponsible entity failed to manage vegetation in a manner such that the responsible entityTransmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.~~	~~The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.~~	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.~~The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.~~	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in~~The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to a grow-in~~

						~~that caused a vegetation-related Sustained Outage.~~
R2	Real-time	Medium	~~The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entityTransmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.~~	~~The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.~~	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.~~The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entityTransmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.~~	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in~~The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.~~
R3	Long-Term Planning	Lower		The responsible entity ~~Transmission Owner~~ has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The responsible entity ~~Transmission Owner~~ has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The responsible entity ~~Transmission Owner~~ does not have any maintenance strategies or documented procedures or processes or specifications used to prevent

				inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's ~~Transmission Owner's~~ applicable lines. (Requirement R3, Part 3.2)	movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's ~~Transmission Owner's~~ applicable lines. Requirement R3, Part 3.1)	the encroachment of vegetation into the MVCD, for the responsible entity's ~~Transmission Owner's~~ applicable lines.
R4	Real-time	Medium			The responsible entity ~~Transmission Owner~~ experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity ~~Transmission Owner~~ experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity ~~Transmission Owner~~ did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The responsible entity ~~Transmission Owner~~ failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity ~~Transmission Owner~~ failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity ~~Transmission Owner~~ failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity ~~Transmission Owner~~ failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity ~~Transmission Owner~~	The responsible entity ~~Transmission Owner~~ failed to	The responsible entity ~~Transmission Owner~~ failed to	The responsible entity ~~Transmission Owner~~ failed to

			failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

Guideline and Technical Basis

Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner~~Transmission Owner~~, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner~~Transmission owner~~, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspections:

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the definition of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Operator~~ or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3: R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.

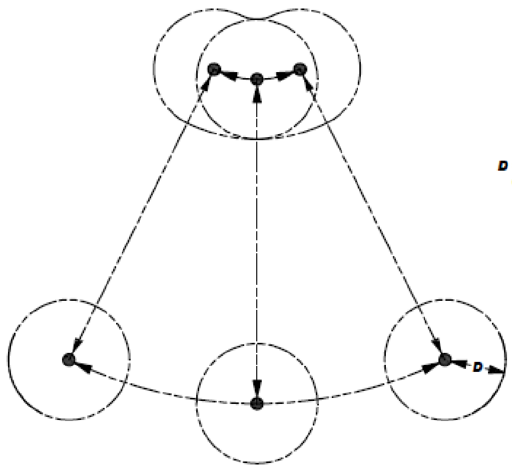

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner's~~ employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners ~~Transmission Owners~~ may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ annual plan, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners ~~Transmission Owners~~ may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner~~Transmission Owner~~, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[8]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[9]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[8] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[9] Where applicable lines are operated at nominal voltages other than those listed, t~~T~~he applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	**Over 500 ft up to 1000 ft**	**Over 1000 ft up to 2000 ft**	**Over 2000 ft up to 3000 ft**	**Over 3000 ft up to 4000 ft**	**Over 4000 ft up to 5000 ft**	**Over 5000 ft up to 6000 ft**	**Over 6000 ft up to 7000 ft**	**Over 7000 ft up to 8000 ft**	**Over 8000 ft up to 9000 ft**	**Over 9000 ft up to 10000 ft**	**Over 10000 ft up to 11000 ft**
	(Over sea level up to 152.4 m)	**(Over 152.4 m up to 304.8 m**	**(Over 304.8 m up to 609.6m)**	**(Over 609.6m up to 914.4m**	**(Over 914.4m up to 1219.2m**	**(Over 1219.2m up to 1524m**	**(Over 1524 m up to 1828.8 m)**	**(Over 1828.8m up to 2133.6m)**	**(Over 2133.6m up to 2438.4m)**	**(Over 2438.4m up to 2743.2m)**	**(Over 2743.2m up to 3048m)**	**(Over 3048m up to 3352.8m)**
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet "wet" formulas are not vastly different when the same transient overvoltage factors are used; the "wet" equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.
The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Implementation Plan for FAC-003-3 ~~-~~ — Transmission Vegetation Management

Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 ~~– Vegetation Management must be implemented~~that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The "clock" for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard~~ can~~). Generator Owners will be ~~implemented~~required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The "clocks" for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The "clocks" for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired ~~when~~at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

Vegetation Inspection

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

Minimum Vegetation Clearance Distance (MVCD)
The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC glossary upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

Compliance with Standard

~~There are no changes to~~As outlined above under "Prerequisite Approvals," the ~~requirements applicable to~~ inclusion of Transmission Owners ~~already proposed~~ in this implementation plan will depend on order in which regulatory authorities approved FAC-003-2~~,~~ and ~~the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.~~

~~The proposed changes to Version 2 of the standard only address Generator Owner applicability and requirements (add Generator Owner to sections 4.1.2 and 4.~~FAC-003-3 ~~and add applicable Generator Owner to all requirements).~~. Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission

Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming (as is required by FAC-003-3 Requirement 1.3). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation (as required in FAC-003-3 Requirement 1.2). On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

Effective Date

There are ~~three~~two effective dates associated with this implementation plan:

The first ~~effective date applies to Transmission Owners.~~

~~In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.~~

~~The second~~ effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The ~~third~~second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

~~Exceptions:~~
Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or ~~as~~designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being ~~subject~~an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to ~~this standard.~~become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher ~~that~~which is newly acquired by an asset owner and which was not previously subject to this standard~~,~~ becomes subject to this standard 12 months after the acquisition date~~ of the line.~~.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations

2. **Number:** PRC-004-2.1

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption. ~~The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.~~

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
3	XX	Errata change: Edited R2 to add “…and	Revision under Project

		generator interconnection Facility…”	2010-07

Implementation Plan for PRC-004-2.1—Analyis of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. PRC-004-2 will be retired when PRC-004-2.1 becomes effective.

Compliance with Standard

The proposed change to Requirement R2 is a clarifying change. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System Misoperations, exclusive of its generator interconnection Facility. The errata change to R2 makes clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

Effective Date

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

137 FERC ¶ 61,141
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Cedar Creek Wind Energy, LLC — Docket No. RC11-1-001
Milford Wind Corridor Phase I, LLC — Docket No. RC11-2-001

ORDER DENYING REHEARING AND PARTIALLY GRANTING CLARIFICATION

(Issued November 17, 2011)

1. On June 16, 2011, the Commission denied the appeals of two registry decisions in which the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), found that two entities, Cedar Creek Wind Energy, LLC (Cedar Creek) and Milford Wind Corridor Phase I, LLC (Milford), were properly included on the NERC Compliance Registry as transmission owners and transmission operators.[1] Several parties requested rehearing and/or clarification of the June 16 Order. In this order, we deny the requests for rehearing and partially grant the clarifications as discussed below.

I. Background

A. Appeals of NERC Registry Decisions

1. NERC's Cedar Creek Decision

2. In its October 6, 2010 decision (Cedar Creek Decision), NERC upheld Western Electricity Coordinating Council's (WECC's) registration of Cedar Creek as a transmission owner and operator. NERC explained that Cedar Creek meets the requirements of section III.d.1 of the Registry Criteria. NERC concluded that Cedar Creek's tie-line is an "integrated transmission element" as described in the

[1] *Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC*, 135 FERC ¶ 61,241 (2011) (June 16 Order). The Commission addressed both appeals in the June 16 Order given the similarity of issues raised in the two proceedings.

Registry Criteria because the line is the link between its generation facility and Public Service Company of Colorado's (PSCo's) Keenesburg Switching Station, "both of which are material to and part of the [Bulk-Power System]."[2] NERC also supported its conclusion that Cedar Creek's registration was proper by stating that Cedar Creek's facilities have a material impact on the Bulk-Power System in part due to Cedar Creek's admission that, if its generator tie-line were lost, it could not execute sales of power or move that power onto PSCo's transmission system. NERC also noted WECC's argument that "improper maintenance and operation of the Cedar Creek 230 kV transmission line and associated transmission equipment could have an impact on reliability far beyond the loss of the generating facility."[3] NERC thus found that a gap in reliability would occur if Cedar Creek is not registered as a transmission owner and operator.

2. Cedar Creek's Appeal to the Commission

3. On October 27, 2010, Cedar Creek filed its request for appeal of NERC's Cedar Creek Decision. Cedar Creek argued that NERC's finding that Cedar Creek is properly registered as a transmission owner and operator is inconsistent with the Registry Criteria. Cedar Creek stated it should be exempt from registration under the plain language of the Registry Criteria and that no showing can be made that such exemption should be over-ridden due to concerns about Bulk-Power System reliability. In support that its line is not integrated, Cedar Creek argued that generator lead lines consist of limited and discrete facilities that do not form an integrated transmission grid but merely connect two points without any electrical breaks between the two points. Cedar Creek contended that its registration as a transmission owner and operator is not necessary for the reliable operation of PSCo's transmission system. Cedar Creek argued that NERC's "claims of the 'importance' and 'integral' nature of Cedar Creek's generator tie-line are patently wrong ."[4]

3. NERC's Milford Decision

4. In its October 6, 2010 decision (Milford Decision), NERC upheld WECC's registration of Milford as a transmission owner and operator. NERC concluded that Milford meets the Registry Criteria requirements for owning and operating an integrated transmission element associated with the Bulk-Power System. NERC

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[2] Cedar Creek Decision at 10.

[3] *Id.* 10-11.

[4] Cedar Creek Appeal at 8.

stated that, because Milford's line is the link between its generating facility and the Intermountain substation, both of which are material to and part of the Bulk-Power System, loss of the Milford line would result in the loss of a generating facility which is material to the Bulk-Power System. NERC reasoned that, under the Registry Criteria, if an integrated transmission element associated with the Bulk Power System exceeds 100 kV, it is by definition a transmission facility. Given that Milford acknowledges its interconnection facilities interconnect the generating facility to the Bulk-Power System by way of the 345 kV Intermountain Power Project, NERC concluded that Milford meets the requirement as an entity that owns and operates an integrated transmission element associated with the Bulk Power System.

4. Milford's Appeal to the Commission

5. On October 27, 2010, Milford filed its request for appeal of the NERC's Milford Decision. Milford argued that it should not be registered as a transmission owner or operator because it does not meet the definitions in the Registry Criteria. Milford noted that the definition of "bulk electric system" does not generally include "radial transmission facilities servicing only load with one transmission source" and argued that the Milford tie-line is such a radial line. Milford argued that the tie-line is not integrated into the bulk electric system and thus does not meet the thresholds in the NERC Registry Criteria. Milford also argued that its system impact study shows that there are no adverse system impacts with its connection to the Intermountain AC Switchyard.

B. June 16 Order

6. In the June 16 Order, the Commission denied Cedar Creek's and Milford's appeals and affirmed that Cedar Creek and Milford are properly registered as transmission owners and operators. The Commission affirmed the NERC registrations, based on the specific facts of the cases, that the reliable operation and maintenance of the Cedar Creek and Milford facilities were material to the reliability of the Bulk-Power System.[5]

7. With regard to Cedar Creek's tie-line, the Commission found that improper protection coordination and operation of the Cedar Creek 230 kV transmission line and associated transmission equipment could have an impact on reliability beyond the loss of the Cedar Creek generating facility.[6] The Commission found that the record indicates that Cedar Creek owns and controls equipment at one end of the

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[5] June 16 Order, 135 FERC ¶ 61,241 at P 58.

[6] *Id.* P 59-62.

tie-line and that some of this equipment, specifically the 230 kV circuit breakers and associated tie-line protective relays, provides Cedar Creek control over the switching of one end of the tie-line.[7] The Commission concluded that equipment at the Cedar Creek end is important because its operation must be coordinated with the equipment at the other end of the line that is under the control of PSCo. If coordination does not occur, or is performed improperly, the Commission stated that there is the potential that operation of this equipment could have impacts beyond the generating facility and tie-line to the Bulk-Power System. The Commission rejected Cedar Creek's reliance on the PSCo system impact study to conclude that there are no reliability impacts. The study, among other things, did not evaluate the impact of improper protection coordination or improper operation of the facilities on Bulk-Power System reliability.

8. With regard to Milford, the Commission found that the record in the proceeding indicated that Milford owns and operates all equipment at one end of the tie-line and that Milford has operational and maintenance jurisdiction of all equipment at the Milford Facility.[8] The Commission concluded that the scope of equipment under Milford's control must be coordinated with the equipment at the remote end of the line that is under the control of Los Angeles Department of Water and Power (LADWP) and without proper coordination, there is the potential that operation of this equipment could have impacts beyond the Milford generating facility and tie-line. The Commission dismissed reliance on Milford's system impact study because it does not evaluate the impact of protection system miscoordination or switching errors. The Commission noted that the system impact study does identify the need for the Milford facilities to be included in a special protection system, proper operation of which is necessary to keep the system from exceeding system operating limits or interconnection reliability operating limits. Therefore, the Commission found that improper coordination of the special protection system with other Bulk-Power System facilities could lead to wide area impacts on the WECC system. The Commission reasoned that all of these factors adequately supported a finding that the Milford facilities are material to the Bulk-Power System.

9. In the case of both Cedar Creek and Milford, the Commission found that that their respective tie-line facilities have a material impact on Bulk-Power

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[7] *Id.* P 60, n.49. Specifically, Cedar Creek controls the following equipment: three 230 kV Generation Breakers; one 230 kV Generator Tie-Line Primary Relay; one 230 kV Generator Tie-Line Secondary Relay; and one 230 kV Generator Tie-Line Bus Relay.

[8] *Id.* P 74-76.

System reliability and concluded that if adequate reliability requirements, including coordination of protection systems, operations and maintenance and properly trained and certified staff are not provided for on the facilities, there is a reliability risk that would affect the Bulk-Power System in WECC. Based on that analysis, the Commission found that at a minimum Cedar Creek and Milford should be required to comply with certain Reliability Standards and directed WECC and NERC to negotiate with Cedar Creek and Milford as to what additional Reliability Standards and Requirements will be applicable.[9]

C. <u>Requests for Rehearing and Clarification</u>

10. The following parties requested rehearing of the June 16 Order: Cedar Creek, Milford, American Wind Energy Association (AWEA), Dominion Resources Services, Inc. (Dominion), and E.ON Climate & Renewables North America LLC (E.ON). The following parties requested clarification, or in the alternative rehearing: NERC, National Rural Electric Cooperative Association (NRECA) and Electric Power Supply Association joined by Independent Power Producers of New York, Inc., TransCanada Power Marketing Ltd. and TransCanada Maine Wind Development Inc., and KGen Power Management Inc. (collectively, EPSA).

11. Several entities argue that there is no factual support that the lines are material to Bulk-Power System reliability.[10] In the case of the Cedar Creek line, Cedar Creek states that nothing could happen on its line that could affect the transmission grid at or beyond the Keenesburg Switching Station because the tie line is radial and PSCo can disconnect the line from the grid if any fault occurs. Cedar Creek states that the Commission's conclusion that the line is material because improper protection coordination and operation of the line could have an impact on the Cedar Creek facility is misplaced. Cedar Creek also argues that the

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[9] *Id.* P 71, 87. The Commission found that Cedar Creek should comply with the following standards: PRC-001-1, Requirements R2, R2.2, R4; PRC-004-1 Requirement R1; TOP-004-2, Requirements R6, R6.1, R6.2, R6.3, R6.4; PER-003-1, Requirements R1, R1.1, R1.2; FAC-003-1, Requirements R1, R2; TOP-001, Requirement R1 and FAC-014-2, Requirement R2. The Commission identified the following standards that should be applicable Milford: PRC-001-1, Requirements R2, R2.2, R4, R6; PRC-004-1 Requirement R1; TOP-004-2, Requirements R6, R6.1, R6.2, R6.3, R6.4; PER-003-1, Requirements R1, R1.1, R1.2; FAC-003-1, Requirements R1, R2; TOP-001, Requirement R1 and FAC-014-2, Requirement R2.

[10] *E.g.* Cedar Creek, Milford, EPSA, AWEA, E.ON.

Commission's conclusion that it did not find persuasive that Cedar Creek has no operational control over its tie lines is inconsistent with a February 2011 Commission Order[11] in which the Commission recognized that PSCo operates the entire line and fails to recognize that PSCo can disconnect the line if any fault on the tie line were to occur. Cedar Creek and Milford and others also argue that the registration as transmission owners/operators represents a departure from the circumstances the Commission relied on in *New Harquahala*.[12]

12. In addition, Cedar Creek and EPSA argue that not relying on the system impact study was erroneous and that PSCo's restudy refutes the speculation that a fault on the tie line would impact the Rocky Mountain Energy Center. They add that the Commission did not cite evidence that system conditions have changed to prove that SIS are outdated which brings into question the value of performing studies if the results will be automatically discounted.[13] Cedar Creek notes that it is already subject to coordination measures with respect to system protection facilities that are identical to those that would be imposed as a transmission owner/operator.

13. Several entities argue that the Commission erred in finding that a reliability gap would occur if Cedar Creek is not registered as a transmission owner/operator.[14] Cedar Creek states that PSCo controls the interaction between the tie line and PSCo's system as a basis for concluding that there is no gap if Cedar Creek is not registered. Cedar Creek adds that it is already subject to the substance of the most critical standards through identical or similar requirements as a generator owner/operator and that PSCo already complies with the necessary standards to ensure no reliability gap. Cedar Creek insists that there is no effect on the Bulk-Power System because Cedar Creek is the only party disadvantaged by a failure to comply with the relevant standards. Cedar Creek, AWEA and E.ON

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[11] *Cedar Creek Wind Energy, LLC*, 134 FERC ¶ 61,130 (2011) (February 17 Order).

[12] *New Harquahala Generating Company, LLC*, 123 FERC ¶ 61,173, *order on clarification*, 123 FERC ¶ 61,311 (2008) (*New Harquahala*) (finding that NERC adequately supported the registration of New Harquahala, which owns and operates a 1,092 MW generator and 26-mile tie line, as a transmission owner and operator based on NERC's authority to register entities that own or operate assets that are material to the reliability of the Bulk-Power System).

[13] EPSA Rehearing Request at 25-27.

[14] *E.g.*, Cedar Creek, EPSA, AWEA , E.ON.

contend that the reliability gaps are ones that exist for all interconnection facilities and thus the Commission's order has the effect of unduly discriminating against Cedar Creek by treating it in a disparate manner from other generators.[15]

14. Milford and EPSA argue that the Commission's fact-specific analysis is not based on facts and ignores the record.[16] Milord also argues that there is nothing in the June 16 Order that differentiates Milford from the vast majority of generators or that addresses the specific facts presented by Milford. Milford contends that its engineering affidavit makes clear that the tie-line is a radial interconnection facility and that the Commission did not analyze or explain why it disagreed with Milford's analysis. In addition, Milford states that the Commission relied on unsupported conjecture that a fault on the Milford generator tie line could cause a loss on the IPP switchyard; this conclusion, without support, directly contradicts unrebutted expert testimony. Milford and AWEA claim that the Commission provided no statements concerning NERC's analysis and did not provide any substantive discussion of why it disagreed with contrary facts and evidence in the record.

15. Next Milford argues that there is no basis for the Commission's selection of the required Reliability Standards, stating, for example, there is no explanation of why Milford should be required to have NERC-certified operators on duty 24 hours a day to address highly infrequent operation of the breakers as opposed to the Commission not having a concern for the many much larger power plants that cycle on and off line with much greater frequency. Milford also argues that the Commission ignored significant facts and argument and did not analyze the facts to create a reasoned decision, and that the decision is based on conclusory statements and unsupported conjecture.

16. Some petitioners argue that the Commission erred by not addressing the plain language of section III(d) of the NERC Statement of Compliance Registry Criteria and its own precedent that tie lines are not integrated facilities.[17] Some also argue that the Commission failed to consider the NERC Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface findings.[18] Entities also claim that the Commission failed to engage in reasoned

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[15] *E.g.,* AWEA Rehearing Request at 21.

[16] Milford Rehearing Request at 12; EPSA Rehearing Request at 39.

[17] *E.g*., Cedar Creek and EPSA.

[18] NERC Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface, (Nov. 16, 2009) (GO/TO Report). In the GO/TO

decision-making by ruling on the appeals without ordering NERC to consider the GO/TO Report and should require expeditious work to complete the standards revisions effort in standards drafting team evaluating the GO/TO Report.[19]

17. In the same vein, EPSA asks that the Commission clarify that it did not intend either to prejudice the outcome of Project 2010-17 or that the standards identified in the June 16 Order must be applied to all generator interconnection facilities. EPSA also asks that the Commission clarify its rationale in finding that the lines are material to reliability and explain how it is narrowly tailored to the specific facts of the cases.

18. EPSA argues that the Commission's interpretation of the materiality provision in the Registry Criteria is overly broad because it would permit registration of any entity to any function where the Commission determines that the entity should be subject to a particular requirement regardless of whether the Standard was developed for application to the type of entity being registered. Several entities argue that the June 16 Order does not apply or discuss the Registry Criteria and is also a departure from precedent that does not allow the Registry Criteria to be supplemented.[20] EPSA also states that the June 16 Order fails to consider the due process rights of affected generator owners and operators because it sidesteps the standards development process to fix a potential reliability gap. EPSA also argues that Cedar Creek and Milford had no notice they had to comply with the transmission owner/operator requirements.[21] Next EPSA claims that the Commission failed to address comments on the definition of "integrated transmission element" and in the order implicitly held that generator interconnection facilities are synonymous with integrated transmission facilities.[22]

Report, the Ad Hoc Group recommended modifications to NERC's Rules of Procedure, Registry Criteria, and other documents to reflect that a generation operator should not be registered as a transmission operator on the basis of the generator interconnection facility. The GO/TO Report also recommended that certain Reliability Standards should apply to generator tie-lines.

[19] *E.g.,* Cedar Creek, AWEA and Dominion.

[20] *E.g.,* Milford, EPSA.

[21] EPSA Rehearing Request at 17.

[22] *Id.* at 24.

19. NRECA requests that the Commission clarify how the NERC Registry Criteria requirement of an "integrated transmission element" or any other specific criteria has been satisfied based on the record. NERC and others request that the Commission clarify that the list of standards from the June 16 Order are not intended to prejudge or dictate the outcome for the GO/TO effort. Several petitioners request clarification that the concerns identified in the list of minimum transmission owner/operator requirements are to be treated as the equivalent of FPA Section 215(d)(5) directives and that the identified standards were for illustrative purposes and not intended to mandate compliance with the specific requirements in advance of the Commission-ordered negotiations, consistent with *New Harquahala*. NERC adds that the Commission should clarify the rationale and explain how its materiality findings are narrowly tailored to the specific facts and are not applicable to all generator interconnection facilities.

II. Discussion

A. Commission Determination

20. The requests for rehearing are denied, and, as discussed below, the Commission reaffirms its previous ruling that Cedar Creek and Milford should be registered as transmission owners and transmission operators. We reaffirm our conclusions with respect to the applicability of the identified Reliability Standards. In addition, as discussed below, the Commission partially grants and partially denies the requested clarifications to the June 16 Order.

1. Preliminary Matters

21. Several entities argue that the Commission did not engage in reasoned decision-making on the grounds that the June 16 Order does not provide any substantive discussion of facts and arguments opposing registration or fully articulate the basis for the decisions. We disagree. There is ample discussion in the June 16 Order of the reasons for the conclusion that the Cedar Creek and Milford lines should be registered as transmission owners and operators. The Commission addressed arguments that NERC misapplied the Registry Criteria by concluding that, in following its *New Harquahala* precedent and conducting a fact-specific analysis, it was not necessary to interpret NERC's application of the Registry Criteria. The Commission also addressed the inappropriateness of using system impact studies in the context of Reliability Standards and reviewed and relied on record evidence to conclude that the lines are important to the Bulk-Power System and that there would be a reliability gap if Cedar Creek and Milford were not registered as transmission owners/operators.[23]

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[23] *See, e.g.*, June 16 Order, 135 FERC ¶ 61,241 at P 58, 60-63, 74-77.

22. Cedar Creek and Milford argue that the Commission did not engage in a fact-specific analysis of the type that the Commission undertook in *New Harquahala*. They also argue that the facts in *New Harquahala* are distinguishable from the facts here and therefore they should not be required to register as transmission owners and operators. In support of these arguments, Cedar Creek and Milford, for example, claim differences between their lines and the facilities at issue in *New Harquahala*. We disagree with these arguments. *New Harquahala* did not establish registration criteria for all generator owners and operators relative to tie-lines nor did it set any parameters for transmission owner and operator registration relative to tie-lines. Instead, in *New Harquahala*, the Commission performed a fact-specific analysis to determine whether New Harquahala should be required to register as a transmission owner and operator. In the June 16 Order, the Commission also conducted a fact-specific analysis based upon the unique characteristics of Cedar Creek and Milford to determine whether each of these entities should be required to register as transmission owners and operators. In applying a fact-specific analysis, the June 16 Order recognized that Cedar Creek's and Milford's facilities are unique and, thus, made a determination on the Cedar Creek and Milford facts, respectively. In other words, as in *New Harquahala*, the Commission ruled solely on the appeal before it based solely on the facts before us.

23. Cedar Creek contends that the June 16 Order is in conflict with the February 17 Order in which, Cedar Creek states, the Commission "recognized" that PSCo has operational control over the entire line.[24] Cedar Creek is mistaken. "Operational control" has more aspects than Cedar Creek represented. For example, Cedar Creek states that PSCo owns, operates and maintains the 4 miles of line into the Keenesburg Switching Station, and the line breaker, line disconnect, and ground disconnect equipment located in the Keenesburg Switching Station. While Cedar Creek identifies 230 kV equipment that is associated with the Cedar Creek end of the line, it does not acknowledge that this equipment provides Cedar Creek with operational control over its end of the line. Cedar Creek also fails to address coordination of operation of the 230 kV equipment at its end with those at the PSCo end. In addition, the statement in the February 17 Order upon which Cedar Creek relies was not a Commission ruling but merely a restatement of what was stated in the application in that proceeding.

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[24] February 17 Order, 134 FERC ¶ 61,130 at P 4, n.11. "PSCo owns, operates, and maintains the other 4 miles of tie line into the Keenesburg Switching Station and the line breaker, line disconnect, and ground disconnect equipment located in the Keenesburg Switching Station. PSCo has operational control over the entire 76 mile tie line."

The Commission did not rely on the language cited by Cedar Creek in the discussion. Thus, the June 16 Order is not inconsistent with the February 17 Order.

2. GO/TO Report And Requests for Clarification

24. Milford contends that there is no basis for the required Reliability Standards and that only the Reliability Standards that should be mandated are those set forth in GO/TO Report. Similarly, Cedar Creek and others argue that the Commission erred by not considering the GO/TO Report's recommendations.[25]

25. In the June 16 Order the Commission recognized that application of transmission owner/operator Reliability Standards more generally is an issue not appropriately addressed in the context of these two registry appeals.[26] Contrary to Milford's assertion, we did not encourage adoption of the GO/TO Report recommendations. Rather, in the June 16 Order we encouraged "NERC to develop an approach to this matter that satisfies Bulk-Power System reliability concerns and also allows entities to understand upfront the scope of their compliance responsibilities."[27] To do as Milford and Cedar Creek request would be inappropriate because it would not allow the standards drafting team currently evaluating the GO/TO Report to complete its work nor allow for industry input on the standard drafting team's suggested resolution or to consider alternative solutions. For the same reasons, it would be inappropriate to apply only the Reliability Standards that are set forth in GO/TO Report. AWEA also requests that the Commission should direct NERC to complete the Project 2010-07 GO/TO standards development process within six months of this order. We reject this as outside the scope of this proceeding and as an inappropriate intrusion on the NERC standards development process.

26. Entities request that the Commission clarify that the determination of the Reliability Standards that Cedar Creek and Milford must comply with is not intended to prejudge the outcome of the Project 2010-07 standards development effort.[28] EPSA seeks clarification that the determinations in these proceedings are not generic determinations and that the Commission is not requiring NERC to find

[25] AWEA Rehearing Request at 21.

[26] June 16 Order, 135 FERC ¶ 61,241 at P 90.

[27] *Id.*

[28] *E.g.* NERC, NRECA, EPSA.

that the Reliability Standards identified in the June 16 Order must be applied to all generator interconnection facilities. We grant these clarifications. NERC, through its standard development process in Project 2010-07 is analyzing more generally which standards should be applicable to all generator interconnection lines, and industry will have input into NERC's determination. Our determinations in this proceeding apply solely to Cedar Creek and Milford, since our analysis in these cases was based solely on the facts in these proceedings. As such, these proceedings do not prejudge NERC's ongoing effort.

27. Because we grant these clarifications, we dismiss EPSA's concern that the Cedar Creek and Milford registrations as transmission owner/operators subject all generators to mandatory requirements to which they had no notice that they had to comply. The Reliability Standard Requirements that we imposed in these proceedings only apply to Cedar Creek and Milford. That order made no finding as to their applicability to other generator owners or operators. Any generator owner or operator has the opportunity to participate in Project 2010-07 to propose which standards should be applicable to generator interconnection lines. EPSA's argument that we failed to consider the due process rights of affected generator owners and operators because the June 16 Order sidesteps the standards development process to fix a potential reliability gap is, therefore, rejected.

28. We deny NERC and NRECA requests for clarification that the requirements identified in the June 16 Order were for illustrative purposes and not intended to mandate compliance with those specific requirements. In the June 16 Order, based on the facts of those cases, we stated that Cedar Creek and Milford must comply with certain transmission owner/operator Reliability Standards and that the negotiations that the Commission ordered were to determine whether any *additional* Reliability Standards and Requirements should be applicable to Cedar Creek and Milford.[29] We note that WECC's and NERC's underlying decisions had the effect of applying *all* the transmission owner/operator Reliability Standards to Cedar Creek and Milford. In the June 16 Order, while upholding NERC's decisions we concluded that a reliability gap would occur if Cedar Creek and Milford were not registered as transmission owner/operators and subject to at least some of the requirements. We concluded that Cedar Creek and Milford needed to comply with only a small subset of the transmission owner/operator Reliability Standards. Such a decision does not, however, dictate the outcome of the Reliability Standard development process or the Project 2010-07 effort. Again, the Commission's decision in the June 16 Order is only applicable to Cedar Creek and Milford. Thus, the Commission affirms that Reliability Standards described in the June 16 Order are ones with which Cedar Creek and Milford must comply, and were not listed for illustrative purposes.

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[29] June 16 Order, 135 FERC ¶ 61,241 at P 72, 88.

3. **Material Impact and Reliability Gaps**

29. Entities argue that the Commission erred in finding that the generator tie-lines are material to the Bulk-Power System.[30] Specifically, Milford argues that the Commission erred in finding that the Milford generator tie-line is material to the Bulk-Power System and by not applying the Registry Criteria or addressing the definition of "integrated transmission element." In a similar vein, NRECA requests that the Commission clarify how the June 16 Order supports a determination that Cedar Creek and Milford's registration is consistent with the Registry Criteria. In the June 16 Order, the Commission noted that NERC has plenary authority to register entities that own or operate assets that are "material to the reliability of the Bulk Power System."[31] Thus, making a finding based on the materiality of a facility is consistent with the Registry Criteria. The Commission considered the importance and impact of the Cedar Creek facilities, as well as the reliability gap that could result if the facilities were not properly registered. The Commission concluded, based on the specific facts, that the reliable operation and maintenance of the interconnection facilities connected to Cedar Creek and Milford generating facilities were material to the reliability of the Bulk-Power System. In basing its decisions on fact-specific analyses and concluding that the facilities are material, the Commission expressly stated that "we need not address the issues raised regarding the interpretation of section III(d)(1) of NERC's Registry Criteria and the definition of an 'integrated transmission element'."[32] Undertaking the analyses in this manner was consistent with our precedent in *New Harquahala*, which applied a fact-specific analysis of a registry appeal that is the same fact-specific analysis we undertook for the registry appeals now before us. For these reasons, we dismiss the claims that the Commission erred by not addressing that the lines do not fit within the tests for inclusion in the bulk electric system and that the Commission did not apply the Registry Criteria or address the definition of "integrated transmission element", and we also decline to provide the clarification requested by NRECA.

30. We are not persuaded by Cedar Creek's argument that the Commission erred in finding that its generator tie-line is material to the Bulk-Power System. Cedar Creek bases its argument on the fact that the line is radial and PSCo

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[30] *E.g.*, Cedar Creek, EPSA, AWEA and E.ON.

[31] June 16 Order at P 58 (*quoting* NERC Registry Criteria, Notes to Criteria, note 1).

[32] *Id*.

operates circuit breakers and line disconnects on its portion of the line with which it could disconnect the line if any fault were to occur. Cedar Creek's argument misses the fact that proper fault-clearing on the line depends on coordination of relays at *both* ends. Cedar Creek does not dispute that it controls protection relays on one end of the tie-line, and it does not refute that the relays on both ends must be coordinated. The Commission found that, specific to Cedar Creek's tie line, protection on Cedar Creek's tie-line requires proper operation of the protective relays and associated equipment on both ends of the line. Without such coordination, Cedar Creek's tie-line protection may fail to timely clear faults, necessitating fault clearing by downstream protection systems, and affecting facilities beyond the tie-line. As noted above, the Commission made a finding that is specific to Cedar Creek's line.

31. The Commission also rejects Cedar Creek's and Milford's arguments that the Commission erred in dismissing the use of the system impact studies to determine the impact of the respective tie-lines on the Bulk-Power System. The Commission also disagrees with Milford's contention that the Commission did not explain why it disagreed with Milford's witness and his explanation of why the system impact study shows that there is no reliability gap. To the contrary, in the June 16 Order, the Commission explained that the system impact studies presented by Cedar Creek and Milford do not address the possible consequences of protection system coordination or protection system misoperations on Bulk-Power System reliability.[33] The Commission also explained that the system impact studies used by Milford's witness did not address the impact of Milford-initiated switching errors on Bulk-Power System Reliability.[34]

32. With respect to Milford's witness, he failed to address the system impacts that could result from protection system miscoordination or protection system failure. In addition, the comments by Milford's witness about the operating speed of the relays and the state of the art nature of the relays are inapposite, since these comments assume proper relay coordination. We also disagree with AWEA's argument that the Commission's concern that a fault on the Milford tie-line causing wide-area impacts on the WECC system are not supported by facts on the record. Successful clearing of a fault on the tie-line is only guaranteed when all components of the protection system covering the tie-line facility are functioning properly, and when protection system settings are coordinated to clear faults in the manner consistent with system studies. As the Commission explained in the June 16 Order, proper coordination in accordance with Reliability Standard PRC-001

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[33] *Id.* P 62 and P 76.

[34] *Id.* P 76.

and misoperation correction pursuant to Reliability Standard PRC-004 must be in place to ensure proper operation of the protection schemes on the tie-line facilities.[35]

33. Furthermore, the explanations given by Milford and Cedar Creek do not alleviate our concerns over switching errors. As we explained in the June 16 Order, the record does not demonstrate that Cedar Creek has turned over authority for tie-line switching to PSCo.[36] Cedar Creek only argues that PSCo could alleviate reliability problems by switching the end of the tie-line owned by PSCo. The Commission is concerned with those instances in which Cedar Creek exercises authority to operate the line at its end, and, as stated in the June 16 Order, there is no evidence in the record stating that PSCo or any entity controls the equipment to conduct the necessary switching on the Cedar Creek end of the line.

34. Similarly, we reject Milford's argument that we failed to address its witnesses' testimony. We explained that the record does not support that all switching will be performed under the direction of LADWP in their role as the registered transmission operator for the tie-line.[37] Successful switching of the tie-line facilities in and out of service requires coordination between both entities. Otherwise, switching errors could introduce faults onto the system, or could result in the closing or opening of the tie-line at improper times. Although AWEA and the Milford's witness argue that these switching operations will be "infrequent," they could still occur and the applicability of a Reliability Standard is not based on the frequency of its necessity. As explained in the June 16 Order, if switching occurs it must be under the direction of NERC-certified operators pursuant to Reliability Standard PER-003 and in coordination with neighboring transmission operators, in accordance with Reliability Standard TOP-004.[38] Milford also questions why it should be required to have NERC-certified operators on duty 24 hours a day to address infrequent operation of the breakers as opposed to the Commission not having a concern for the many much larger power plants that

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[35] *Id.* P 78. Moreover, acceptance of Milford's argument would suggest that Reliability Standards should not be applied to an entity until that entity first experienced the failure (e.g., outage) which the Reliability Standards were designed to prevent.

[36] *Id.* P 61.

[37] *See* June 16 Order, 135 FERC ¶ 61,241 at P 75.

[38] *Id.* P 67, 81, 82.

cycle on and off line with much greater frequency. As noted above, the applicability of a Reliability Standard is not based on the frequency of its necessity. Thus, the Commission determined that Milford must have NERC-certified operators on duty based on whether the Reliability Standards should apply, not how often they should apply. Furthermore, we addressed only the specific facts of these two cases that were before us and thus reject Milford's argument as to other plants not before us as outside the scope of this proceeding. Milford could avoid the costs associated with NERC-certification if Milford enters into an agreement with LADWP that turns over control of its end of the tie-line facility to LADWP, with its operators only performing switching under the direction and supervision of the NERC-certified LADWP operator. Such transfer of operational control could also be backed by a negotiated agreement that transfers responsibility for compliance with transmission operator standards to LADWP.[39]

35. Cedar Creek argues that there is no reliability gap because NERC already requires Cedar Creek to comply with the generator owner/generator operator Reliability Standards which, Cedar Creek argues, cover the reliability gaps described by the Commission. Cedar Creek believes that its registration as a generator owner/generator operator should allay the Commission's concerns over relay protection because it is subject to the requirements of Reliability Standard PRC-001 Requirement R2.1 and PRC-004 Requirement R2. However, these generator owner/generator operator requirements do not explicitly obligate communication in connection with relays on generator tie-lines. The inclusion of Reliability Standards PRC-001 Requirement R2.2, PRC-001 Requirement R4, and PRC-004 Requirement R1 ensures that Cedar Creek specifically coordinates tie-line protection with PSCo and reports misoperations associated with tie-line protection to its Regional Entity.

36. Cedar Creek also dismisses the need to comply with other Reliability Standards (TOP-001, TOP-004, FAC-014, PER-003) because, if an operating problem were to occur on the line, PSCo could simply alleviate the problem by operating their breakers at the PSCo end of the line. The Commission is concerned with those instances in which it is necessary to operate the line at the Cedar Creek end, and there is no evidence in the record that PSCo or any entity is controlling the breakers on the Cedar Creek end. Thus, there is no error in the June 16 Order's determination that a reliability gap must be filled by Cedar Creek's registration as a transmission operator.

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[39] *See* Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity, NERC Compliance Public Bulletin No. 2010-004 Section II.1 (Apr. 20, 2010).

The Commission orders:

(A) The Commission hereby denies the requests for rehearing, as discussed in the body of this order.

(B) The Commission hereby grants in part and denies in part the requests for clarification, as discussed in the body of this order.

By the Commission. Commissioner Spitzer is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)