Item descriptor *Note:* The description must match by model number or a broader descriptor that does not necessarily need to be company specific	Date of initial or subsequent BIS classification. (ID = initial date; SD = subsequent date)	Date when the item will be designated EAR99, unless reclassified in another ECCN or the 0Y521 classification is reissued	Item-specific license exception eligibility
0A521. Systems, Equipment and Components			
No.1: Biosensor systems and dedicated detecting components, i.e. cartridges and cells, capable of detecting all of the following aerosolized bioagents: anthrax, ricin, Botulinum toxin, Francisella tularensis, orthopoxvirus and Yersinia pestis, and having all of the following characteristics: a. Capable of showing results in three minutes or less; b. Has an integrated bioaerosol collector and identifier; c. Contains antibodies for any of the bioagents listed above; and d. Utilizes bioluminescence as a process. Related Controls. *(1)* See ECCN 1A004.c for detection systems and ECCN 2B351 for toxic gas monitoring systems and their dedicated detecting components, both of which are different from ECCN 0A521. Biosensor Systems. *(2)* See 22 CFR Part 121, Category XIV (f) (2) for equipment for the detection, identification, warning or monitoring of biological agents that is subject to the export licensing jurisdiction of the U.S. Department of State, Directorate of Defense Trade Controls. Technical Notes: 1. For the purposes of this entry, the term dedicated means committed entirely to a single purpose or device. 2. This entry does not control biosensor systems that detect food borne pathogens.	March 28, 2013 (ID)	March 28, 2014	License Exception GOV under § 740.11(b)(2)(ii) only.
0B521. Test, Inspection and Production Equipment			
[RESERVED].			
0C521. Materials			
[RESERVED].			
0D521. Software			
No. 1 0D521 "Software" for the function of Biosensor Systems controlled by ECCN 0A521.	March 28, 2013 (ID)	March 28, 2014	License Exception GOV under § 740.11(b)(2)(ii) only.
0E521. Technology			
No. 1: 0E521 "Technology" for the "development" or "production" of Biosensor Systems controlled by ECCN 0A521.	March 28, 2013 (ID)	March 28, 2014	License Exception GOV under § 740.11(b)(2)(ii) only.

Dated: March 21, 2013.

Kevin J. Wolf,

Assistant Secretary for Export Administration.

[FR Doc. 2013–07132 Filed 3–27–13; 8:45 am]

BILLING CODE 3510–33–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM12–4–000; Order No. 777]

Revisions to Reliability Standard for Transmission Vegetation Management

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Under section 215 of the Federal Power Act (FPA), the Federal Energy Regulatory Commission (Commission) approves Reliability Standard FAC–003–2 (Transmission Vegetation Management), submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. Reliability Standard FAC–003–2 expands the applicability of the standard to include overhead transmission lines that are operated below 200 kV, if they are either an element of an Interconnection Reliability Operating Limit or an element of a Major WECC Transfer Path. Reliability Standard FAC–003–2 incorporates a new minimum annual inspection requirement, and incorporates new minimum vegetation

clearance distances into the text of the standard.

The Commission also approves the related definitions, violation severity levels, implementation plan, and effective dates proposed by NERC. The Commission approves the related violation risk factors, except that it directs a revision to the violation risk factor corresponding to one requirement.

DATES: *Effective Date:* This rule will become effective May 28, 2013.

FOR FURTHER INFORMATION CONTACT:

Tom Bradish (Technical Information), Office of Electric Reliability, Division of Reliability Standards, Federal Energy Regulatory Commission, 1800 Dual Highway, Suite 201, Hagerstown, MD 21740, Telephone: (301) 665–1391.

David O'Connor (Technical Information), Office of Electric Reliability, Division of Reliability Standards, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426,Telephone: (202) 502–6695.

Jonathan First (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8529.

Julie Greenisen (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–6362.

SUPPLEMENTARY INFORMATION:

Final Rule

Issued March 21, 2013

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standard FAC–003–2 (Transmission Vegetation Management), submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). Reliability Standard FAC–003–2 modifies the currently-effective standard, FAC–003–1 (the ''Version 1'' standard). The proposed modifications, in part, respond to certain Commission directives in Order No. 693, in which the Commission approved FAC–003–1.[2]

2. Reliability Standard FAC–003–2 has a number of features that make it an improvement over the Version 1 standard. For example, like Version 1, FAC–003–2 applies to all overhead transmission lines operated at or above 200 kV, but unlike Version 1, it explicitly applies to any lower voltage overhead transmission line that is either an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.[3] The Reliability Standard also makes explicit a transmission owner's obligation to prevent an encroachment into the minimum vegetation clearance distance (MVCD) for a line subject to the standard, regardless of whether that encroachment results in a sustained outage or fault.[4] Also, for the first time, FAC–003–2 requires transmission owners to annually inspect all transmission lines subject to the standard and to complete 100 percent of their annual vegetation work plan. The Reliability Standard also incorporates the MVCDs into the text of the standard, and does not rely on clearance distances from an outside reference, as is the case with the Version 1 standard. We believe these beneficial provisions, and others discussed below, support our approval of FAC–003–2.

3. A recurring cause in many blackouts has been vegetation-related outages. In fact, one of the initiating causes of the 2003 Northeast blackout was inadequate vegetation management practices that led to tree contact.[5] Further, NERC has identified a focus on preventing non-random equipment outages such as those caused by vegetation as a top priority that will most likely have a positive impact on Bulk-Power System reliability.[6] We also note that industry has made important strides in reducing the instances of vegetation contact.[7] We believe that industry compliance with FAC–003–2, together with a continued focus by industry on best practices for vegetation management, will serve to enhance the reliability of the Bulk-Power System. While we approve NERC's use of the Gallet equation to determine the minimum vegetation clearance distances, we believe it is important that NERC develop empirical evidence that either confirms assumptions used in calculating the MVCD values based on the Gallet equation, or gives reason to revisit the Reliability Standard. Accordingly, consistent with the Notice of Proposed Rulemaking (NOPR) proposal, the Commission directs that NERC conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing.[8]

4. We also approve the three new or revised definitions associated with the proposed Reliability Standard for inclusion in the NERC Glossary. Specifically, we approve the changes in the definition of ''Right-of-Way'' and ''Vegetation Inspection,'' as well as the addition of the term ''Minimum Vegetation Clearance Distance (MVCD)'' as defined in NERC's petition. We also approve NERC's implementation plan for FAC–003–2.

5. NERC has not adequately supported the proposed assignment of a ''medium'' Violation Risk Factor to Requirement R2, which pertains to preventing vegetation encroachments into the MVCD of transmission lines operated at 200 kV and above, but which are not part of an IROL or a Major WECC Transfer Path. As discussed later, system events have originated from non-IROL facilities. Accordingly, we adopt the NOPR proposal and direct NERC to submit a modification, within 60 days of the effective date of the Final Rule, assigning a ''high'' Violation Risk Factor for Requirement R2.

6. As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners.

[1] 16 U.S.C. 824o (2006).

[2] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[3] NERC defines ''IROL'' as ''[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.'' NERC defines ''System Operating Limit'' as ''[t]he value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.'' *See* NERC Glossary of Terms Used in Reliability Standards (NERC Glossary) at 26, 48. The Western Electricity Coordinating Council (WECC) maintains a listing of Major WECC Transfer Paths, *available at http://www.wecc.biz/Standards/Development/WECC-0091/SharedDocuments/WECC-0091TableMajorPaths4-28-08.doc.*

[4] *See* Reliability Standard FAC–003–2, Requirements R1 and R2, subsection 1; *see also* Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard FAC–003–2—Transmission Vegetation Management at 4, 6 (NERC Petition). NERC proposes to define MVCD as ''the calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.'' *Id.* at 2.

[5] *See* U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations at 18, 57–64 (April 2004) (2003 Blackout Report).

[6] *See* written remarks by Gerry Cauley, NERC's Chief Executive Officer, for the November 29, 2011 Reliability Technical Conference at 1, 4 and 5 (Docket No. AD12–1–000).

[7] *See, e.g.,* NERC's Third Quarter 2012 Vegetation-Related Transmission Outage Report at 6–7, *available at http://www.nerc.com/files/Item%202%20-%20Third%20Quarter%20Vegetation%20Report.pdf.*

[8] *Revisions to Reliability Standard for Transmission Vegetation Management,* Notice of Proposed Rulemaking, 141 FERC ¶ 61,046 (Oct. 18, 2012).

I. Background

A. Section 215 of the FPA

7. Section 215 of the FPA requires the Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight, or by the Commission independently.[9] Pursuant to the requirements of FPA section 215, the Commission established a process to select and certify an ERO [10] and, subsequently, certified NERC as the ERO.[11]

B. Reliability Standard FAC–003–2 and NERC Explanation of Provisions [12]

8. Reliability Standard FAC–003–2 includes seven requirements.[13]

9. Requirements R1 and R2: Pursuant to Requirements R1 and R2, subsection 1, transmission owners must ''manage vegetation to prevent encroachments into the MVCD of its applicable line(s),'' and any encroachment is considered a violation of these requirements regardless of whether it results in a sustained outage.[14] In its petition, NERC characterized this as a ''zero tolerance'' approach to vegetation management.[15] According to NERC, these requirements represent an improvement over the Version 1 standard because FAC–003–2 makes the requirement to prevent encroachments explicit, and because it incorporates specific clearance distances into the standard itself based on ''an established method for calculating the flashover distance for various voltages, altitudes, and atmospheric conditions.'' [16]

10. In addition, FAC–003–2 includes a footnote describing certain conditions or scenarios, outside the transmission owner's control, where an encroachment would be exempt from Requirements R1 and R2, including natural disasters and certain human or animal activity.[17] In its petition, NERC explained that the footnote ''does not exempt the Transmission Owner from responsibility for encroachments caused by activities performed by their own employees or contractors, but it does exempt them from responsibility when other human activities, animal activities, or other environmental conditions outside their control lead to an encroachment that otherwise would not have occurred. '' [18]

11. Requirement R3: Requirement R3 requires a transmission owner to 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.'' Requirement R3 requires that these strategies take into account movement of conductors (sag and sway), and the inter-relationship between vegetation growth rates, vegetation control methods, and inspection frequency. While NERC acknowledged that this requirement does not include the Version 1 standard's requirement to establish a Clearance 1, NERC noted that Clearance 1 levels are left largely to the discretion of the transmission owner and that the only numerical criterion for Clearance 1 is that it ''must be some undefined amount larger than the minimum flashover distance [Clearance 2].'' [19] According to NERC, the FAC–003–2 requirement to avoid encroachments after taking into account conductor movement, vegetation growth rates, etc., ''still retains the same obligations defined by 'Clearance 1.' '' [20]

12. Requirement R4: Requirement R4 requires a transmission owner that has observed a vegetation condition likely to produce a fault at any moment to notify, ''without any intentional time delay,'' the appropriate control center with switching authority for that transmission line.

13. Requirement R5: Requirement R5 requires a transmission owner constrained from performing vegetation management work needed to prevent a vegetation encroachment into the MVCD prior to implementation of the next annual work plan to take corrective action to prevent such encroachments. NERC stated in its petition that Requirement 5 improves upon the Version 1 standard provision, Requirement R1.4, which merely requires a transmission owner to develop mitigation measures to address such circumstances, but does not affirmatively require the transmission owner to take corrective action. The proposed measures for determining compliance associated with proposed Requirement R5 provide examples of the kinds of corrective actions expected, including increased monitoring, line de-ratings, and revised work orders.[21]

14. Requirement R6: Pursuant to Requirement R6, each transmission owner must inspect 100 percent of its applicable transmission lines at least once per year and with no more than 18 months between inspections on the same right-of-way. According to NERC, Requirement R6 is ''an improvement to the standard that reduces risks.'' [22] NERC noted that the Version 1 standard allows a transmission owner to develop its own schedule for inspections (with no standard minimum time) and contains no explicit requirement that the transmission owner meet its established schedule.

15. Requirement R7: Pursuant to Requirement R7, the transmission owner must complete 100 percent of its annual vegetation work plan, allowing for documented changes to the work plan as long as those modifications do not allow encroachment into the MVCD. NERC explained in its petition that Requirement R7 represents an improvement because Requirement R2 of the Version 1 standard ''does not mandate that entities plan to prevent encroachments into the MVCD, but simply that they implement whatever is included in the plan.'' [23]

C. Procedural Activities

1. Pacific Northwest National Laboratory Report

16. NERC explained in its petition that the Standard Drafting Team applied the ''Gallet equation'' to derive the MVCDs set forth in FAC–003–2. NERC described the Gallet equation as a ''well-

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[9] *See* 16 U.S.C. 824o(e)(3).

[10] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[11] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g and compliance,* 117 FERC ¶ 61,126 (2006) (certifying NERC as the ERO responsible for the development and enforcement of mandatory Reliability Standards), *aff'd sub nom. Alcoa Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[12] Reliability Standard FAC–003–2 is not attached to the Final Rule. The complete text of Reliability Standard FAC–003–2 is available on the Commission's eLibrary document retrieval system in Docket No. RM12–4–000 and is posted on the ERO's Web site, *available at: http://www.nerc.com.*

[13] The NOPR also provided background on the requirements of the Version 1 standard, FAC–003–1, and the Commission's directives pertaining to the Version 1 standard set forth in Order No. 693. *See* NOPR, 141 FERC ¶ 61,046 at PP 8–16.

[14] *See* Reliability Standard FAC–003–2, Requirements R1 and R2, subsection 1 (transmission owners must manage vegetation to prevent, *inter alia,* ''an encroachment into the MVCD, as shown in FAC–003-Table 2, observed in Real-Time, absent a Sustained Outage'').

[15] NERC Petition at 6.

[16] *Id.* at 22.

[17] *See* proposed Reliability Standard FAC–003–2, n.2.

[18] NERC Petition at 23.

[19] *Id.* at 20. Requirement R1 of the Version 1 standard requires a transmission owner to prepare a transmission vegetation management program that includes, *inter alia,* a Clearance 1 distance to be maintained at the time of vegetation management work, and a Clearance 2 distance to be maintained at all times. *See* NOPR, 141 FERC ¶ 61,046 at P 9.

[20] NERC Petition at 20.

[21] *See id.* at 24–25.

[22] *Id.* at 17–18.

[23] *Id.* at 28. For additional background pertaining to NERC's petition, *see* NOPR, 141 FERC ¶ 61,046 at PP 32–36.

known method of computing the required strike distance for proper insulation coordination.'' [24] The Commission's Office of Electric Reliability retained the Pacific Northwest National Laboratory (PNNL) to undertake an ''analysis of the mathematics and documentation of the technical justification behind the application of the Gallet equation and the assumptions used in the technical reference paper [Exh. A of NERC's petition].'' [25]

17. PNNL's final *Report on the Applicability of the ''Gallet Equation'' to the Vegetation Clearances of NERC Reliability Standard FAC–003–2* (PNNL Report) was posted as part of the record in this docket on April 23, 2012, along with a notice inviting comment on the PNNL Report within 30 days. Nine entities submitted comments in response to the PNNL Report.[26]

2. NERC Response to Data Request

18. On May 4, 2012, Commission staff issued data requests to NERC. NERC submitted a timely response to the data requests on May 25, 2012, addressing matters such as the correct understanding and enforceability of certain provisions of the proposed Reliability Standard. Relevant elements of NERC's response to the data requests are discussed further below.

3. Notice of Proposed Rulemaking

19. On October 18, 2012, the Commission issued a NOPR proposing to approve Reliability Standard FAC–003–2. In addition to seeking comment on various aspects of NERC's petition, the Commission proposed to direct that NERC: (1) Conduct or commission testing to obtain empirical data that either confirms the MVCD values or gives reason to revisit the Reliability Standard and submit a report to the Commission providing the results of the testing; and (2) submit a modification that assigns a ''high'' Violation Risk Factor for Requirement R2.

20. Comments were due on December 24, 2012. Twenty sets of comments were received. The Appendix to the Final Rule identifies the name of commenters. The comments were informative and assisted the Commission in developing this Final Rule. On February 5, 2013, NERC submitted reply comments.

II. Discussion

21. Pursuant to section 215(d) of the FPA, we approve Reliability Standard FAC–003–2, including the associated definitions and implementation plan, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed in Section A below, we believe the proposed Reliability Standard will enhance reliability and satisfies a number of the directives from Order No. 693. We also discuss the following matters below: (A) Approval of FAC–003–2; (B) applicability of the standard to sub-200 kV transmission lines; (C) clearance distances; (D) appropriate Violation Risk Factor for Requirement R2; (E) enforcement issues; (F) inclusion of reporting obligations as a compliance measure; and (G) proposed definitions.

A. The Commission Approves Reliability Standard FAC–003–2

NOPR Proposal

22. In the NOPR, the Commission proposed to approve FAC–003–2, explaining that it improves upon the Version 1 standard by supporting vegetation management practices that can effectively protect against vegetation-related transmission outages, and by satisfying a number of the outstanding directives from Order No. 693.[27] The Commission highlighted several improvements, including the expanded applicability of the Reliability Standard so that it now applies not only to all transmission lines above 200 kV, but also to transmission lines operated below 200 kV if they are an element of an IROL or an element of a Major WECC Transfer Path. The Commission also highlighted that FAC–003–2 incorporates (1) minimum clearance distances into the text of the Reliability Standard and (2) a minimum inspection cycle requirement.

Comments

23. NERC supports the Commission's proposal to approve the proposed Reliability Standard, stating that FAC–003–2 represents a significant step in transmission vegetation management. According to NERC, FAC–003–2 maintains reliability by using a defense-in-depth strategy to manage vegetation located on transmission rights-of-way and by minimizing vegetation encroachments within the transmission owner's control, thus ''preventing the risk of those vegetation-related outages that could lead to a Sustained Outage.'' [28] Further, NERC requests that the Commission give ''due weight'' to NERC's technical expertise and approve FAC–003–2 as filed.

24. Trade Associations support approval of FAC–003–2, stating that the revised Reliability Standard responds to the Commission directives in Order No. 693 and provides a strong defense-in-depth approach to vegetation management, including a requirement for at least annual inspections.[29] Trade Associations agree with the Commission's statement in the NOPR that FAC–003–2 explicitly states minimum clearance distances and that the modified ''applicability'' provision includes additional facilities. Trade Associations state that FAC–003–2 strikes the appropriate balance between establishing minimum criteria and permitting utility-specific variations that will enhance reliability and prevent outages caused by vegetation intrusion. Likewise, AEP, BPA, Idaho Power, ITC Companies, KCPL, Manitoba Hydro, PacifiCorp, PA PUC, PG&E and Southern Companies support approval of FAC–003–2 as an improvement over the currently-effective Reliability Standard, and as addressing the Commission's directives in Order No. 693.

25. NESCOE generally supports FAC–003–2 as representing appropriate enhancements to the Version 1 standard in a number of critical areas. While noting that the Reliability Standard is not designed to address severe weather events and natural disasters such as the October 2011 Northeast snowstorm, NESCOE states that more clearly defined clearance requirements and stricter vegetation management practices should have the attendant benefit of reducing the risk to Bulk-Power System reliability during such events. However, NESCOE believes that NERC should be required to demonstrate that the proposal is supported by a cost analysis, i.e., that the incremental reliability gains outweigh the added costs. Therefore, NESCOE recommends that the Commission grant ''interim approval'' to FAC–003–2, with final approval conditioned on NERC supporting the proposal with a cost-benefit analysis.

26. APS comments that the Version 1 standard, FAC–003–1, has proven effective and the Commission should consider ''maintaining'' that standard. APS notes that the number of outages caused by vegetation grow-in has steadily declined since implementation of the Version 1 standard, and APS

[24] NERC Petition, Ex. I (Technical Reference Document) at 39.

[25] *See* April 23, 2012 Notice Inviting Comments on Report.

[26] For further description of the PNNL Report and comments filed in response to the Report, *see* NOPR, 141 FERC ¶ 61,046 at PP 40–54.

[27] NOPR, 141 FERC ¶ 61,046 at PP 57–61.

[28] NERC Comments at 3.

[29] Duke, KCPL, PacifiCorp, PG&E and Southern Companies support the comments submitted by Trade Associations.

attributes this decline largely to the ''Clearance 1'' requirement that transmission owners develop and document their plan to manage the vegetation on rights-of-way at the time of work. APS expresses concern that a different approach may be less effective. Alternatively, if FAC–003–2 is approved, APS suggests integrating a Clearance 1 requirement in that standard.

Commission Determination

27. We adopt our NOPR proposal and approve Reliability Standard FAC–003–2, including the associated definitions and implementation plan, as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[30] We find that FAC–003–2 is an improvement over the currently-effective Version 1 standard, will support vegetation management practices that can effectively protect against vegetation-related transmission outages, and satisfies a number of the outstanding directives from Order No. 693. As discussed earlier, NERC has explained how many of the Requirements improve upon the currently-effective Version 1 standard. In accordance with our directives in Order No. 693, and as discussed further in Section II.B below, NERC has expanded the applicability of the Reliability Standard so that it now applies not only to all transmission lines operated above 200 kV, but also to transmission lines operated below 200 kV if they are an element of an IROL or an element of a Major WECC Transfer Path.

28. In addition, NERC has incorporated minimum clearance distances into the text of the Reliability Standard, and no longer includes a required clearance distance based on a reference to distances set by Institute of Electric and Electronics Engineers (IEEE) Standard 516 that, as indicated in Order No. 693, served a different purpose than vegetation management. Proposed FAC–003–2 requires a transmission owner to prevent an encroachment into the MVCD, even if the encroachment does not result in a flashover or fault. As NERC explains, ''FAC–003–2 presents a 'zero-tolerance' approach to vegetation management, explicitly treating any encroachment into the MVCD* * * as a violation* * *.''[31] Encroachments must be prevented under all rated operating conditions, and strategies to prevent encroachments must take into account sag and sway of the line, as well as vegetative growth rates and frequency of inspection and maintenance.[32]

29. Further, in Order No. 693 the Commission expressed concern that the Version 1 standard leaves to the discretion of each transmission owner to determine inspection cycles.[33] In response, NERC has addressed this concern by incorporating a minimum inspection cycle requirement in the proposed Reliability Standard (at least once per calendar year and no more than 18 months between inspections).[34]

30. The Commission disagrees with APS and will not maintain the Version 1 standard. While we agree with APS that the Version 1 standard has proven effective in minimizing the number of outages caused by vegetation grow-in, as described above, we conclude that FAC–003–2 includes improvements upon the Version 1 standard. We expect these new features to enhance vegetation management practices and continue the decline in reported vegetation-related outages. Moreover, with regard to APS's concerns on the elimination of the ''Clearance 1'' requirement, we do not believe that this concern supports maintaining the Version 1 standard. As we discuss in more detail later on, under FAC–003–2, transmission owners will manage vegetation to distances beyond the MVCD to ensure no encroachment into the MVCD.[35] Therefore, we are not persuaded that APS's concerns warrant a remand of FAC–003–2.

31. We also disagree with NESCOE that the Commission should grant ''interim approval'' to FAC–003–2, with final approval conditioned on NERC supporting the proposal with a cost-benefit analysis. As NESCOE acknowledges, the Reliability Standard includes enhancements to the Version 1 standard in a number of critical areas. Section 215(d) of the FPA authorizes the Commission to approve or remand a Reliability Standard proposed by the ERO. There is no mention of authority to approve a standard on an ''interim'' basis, or what that approval would entail. In addition, as the Commission has stated, while the cost of implementation is appropriate for consideration among other factors in the development of a Reliability Standard, the Commission has not required the preparation of a cost-benefit analysis for approval of a standard.[36]

32. Accordingly, we approve FAC–003–2 on a final basis, and transmission owners must comply with the Reliability Standard as set forth in NERC's implementation plan.

B. Applicability—Facilities Operated Below 200 kV

NOPR Proposal

33. The Reliability Standard applies to transmission owners. Further, FAC–003–2 applies to (1) overhead transmission lines operated at 200 kV or higher and (2) overhead lines operated below 200 kV if (a) ''identified as an element of an IROL under NERC Standard FAC–014 by the Planning Coordinator'' or (b) ''identified as an element of a Major WECC Transfer Path* * *'' In the NOPR, the Commission asked how IROL status of a facility will be communicated to transmission owners, and how transmission owners can effectively implement this provision since IROL status can change with system conditions.[37] Further, the Commission asked for comment on how FAC–003–2 complies with the Order No. 693 directive that the standard cover ''lines that have an impact on reliability.''[38]

1. Identification and Communication of IROL Status

Comments

34. NERC comments that FAC–003–2 relies on the identification of IROLs by the planning coordinator, which ''would include identifying any changes in the status of a line if a line's IROL status changes given changing system conditions.''[39] NERC further states that Requirement R5 of FAC–014 provides the means for a transmission owner to obtain IROL information. According to NERC, this provision requires the planning authority (a term synonymous

[30] Likewise, we approve as requested by NERC, the retirement of FAC–003–1 and the current definitions of ''right-of-way'' and ''vegetation inspection'' effective ''midnight immediately prior to the first day of the first calendar quarter that is a year following the effective date'' of the final rule. NERC Petition at 2.

[31] NERC Petition at 6.

[32] *See* Reliability Standard FAC–003–2 at p 20–22.

[33] *See* NOPR, 141 FERC ¶ 61,046 at P 59 (citing Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 721).

[34] *See* NERC Petition at 43.

[35] *See* discussion *infra* section II.C.1 (Minimum Clearance Values); *see also* NOPR, 141 FERC ¶ 61,046 at PP 67–70 (discussing NERC Petition and maintenance of vegetation beyond MVCD values).

[36] *See* North American Electric Reliability Corp., 117 FERC ¶ 61,126 at P 97 (2006); *see also* Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 330. To the extent estimated costs are considered, estimated benefits (*e.g.,* in terms of a level of reliability or the risk, duration, scope or economic savings of avoided blackouts) must be considered, either quantitatively or (if quantification is impractical) qualitatively.

[37] NOPR, 141 FERC ¶ 61,046 at P 64.

[38] NOPR, 141 FERC ¶ 61,046 at P 65, quoting Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 708.

[39] NERC Comments at 5.

with planning coordinator) to ''provide its SOLs and IROLs to entities with a reliability-related need, such as a Transmission Owner, who request such information.'' [40] NERC further offers that ''[i]f the Commission does not agree that Transmission Owners can obtain information directly from Planning Coordinators under Requirement R5 of FAC–014,'' transmission owners have other means such as Requirement R8 of Reliability Standard TPL–001–2 as well as existing agreements between transmission owners and transmission operators.[41] Regarding changes in IROL status, NERC comments that the burden is on the transmission owner to procure this information as part of its responsibility to manage vegetation to prevent encroachment and as the entity responsible for implementing FAC–003–2.

35. Likewise, Duke states that, pursuant to FAC–014, a transmission owner can request IROL designations from the planning coordinator, including future changes to IROL status. Duke and AEP comment that FAC–003–2 includes an effective date twelve months after the date a transmission line operated below 200 kV is newly designated as an element of an IROL. They state that this twelve-month period allows time for the transmission owner to modify its vegetation management work plan to include new IROL elements.

36. According to Trade Associations, AEP and FirstEnergy, FAC–014 does not require planning coordinators to notify transmission owners of the designation of IROL facilities. Further, Trade Associations maintain that a vegetation management program is based on the near term planning horizon of one to five years and, thus, applicable entities cannot document compliance with day-to-day operating changes to IROLs. Trade Associations comment that, while this issue should not delay approval of FAC–003–2, it is important to establish a clearly defined communication structure and agreed upon start date for compliance documentation prior to transmission owners' inclusion of IROL elements in their vegetation management programs.

37. FirstEnergy and AEP advocate that the Commission direct NERC to modify FAC–014 to include a requirement that planning coordinators promptly communicate IROL status updates to transmission owners. According to Idaho Power, FAC–003–2 should require that the planning coordinator communicate IROL status to transmission owners. Moreover, Idaho Power suggests that it is reasonable to hold a transmission owner responsible for vegetation management on lines that can become IROLs during ''studied credible contingencies'' but not for unstudied or unanticipated system conditions.

38. BPA suggests that NERC develop an automated electronic notification system to inform affected transmission owners regarding changes in IROL status.

Commission Determination

39. Consistent with the NOPR, we remain concerned regarding how IROL status of a facility will be communicated to transmission owners. We are not persuaded that Reliability Standard FAC–014 requires the communication of IROL status information to transmission owners. Requirement R5 of FAC–014–2 provides:

> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:
>
> R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. * * *

40. While Requirement R5 indicates that SOLs and IROLs should be provided to entities that have a ''reliability-related need'' for that information, this broad language is limited ''as follows'' to the entities specified in sub-Requirement R5.1. Transmission owners are not specified. Further, Requirement R5 of FAC–003 does not include ''for example'' or ''including but not limited to'' language that would suggest the entities specified in sub-Requirement R5.1 are not exclusive. Thus, we conclude that FAC–014–2 does not obligate reliability coordinators, planning authorities and transmission planners to provide IROL information to transmission owners.[42]

41. Rather, we agree with Trade Associations and other commenters that NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners. This structure will better support compliance with the extended applicability of FAC–003–2 to sub-200 kV transmission lines that are an element of an IROL. One way to achieve this objective, as advocated by AEP and others, is to modify FAC–014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners.

42. We do not believe, however, that establishing a communication structure should delay the implementation of FAC–003–2. As NERC indicates, the ultimate responsibility for compliance with FAC–003–2 is upon transmission owners. Moreover, it appears that there are multiple avenues for transmission owners to obtain information about IROL elements on their facilities. For example, NERC represents that, in many instances, the entity responsible for identifying IROL elements on a system is also registered as a transmission owner.[43] Likewise, transmission owners may obtain the necessary information through voluntary communications or pursuant to coordination required in bilateral agreements. As Duke and AEP note, FAC–003–2 includes an effective date that is twelve months after the date a line operated below 200 kV is initially designated as an element of an IROL, which allows time for the transmission owner to modify its vegetation management work plan to include new IROL elements. We encourage NERC to inform us when it has developed means for communication of IROLs to transmission owners to help ensure they receive notice of each of their applicable lines before the standard becomes effective as to those lines.

43. With regard to the concern in the NOPR on the changing status of IROLs, we accept the explanation of Trade Associations that a vegetation management program should be based on the near term planning horizon of one to five years, in which case applicable transmission owners will not be responsible to document compliance with day-to-day operating changes to IROLs. Likewise, we agree with Idaho Power that transmission owners should be responsible for vegetation management on lines that can become IROLs during ''studied credible contingencies.'' Based on the methodology set forth in FAC–014, sub-200 kV transmission lines that are identified as elements of an IROL or Major WECC Transfer Path are subject to FAC–003–2. For example, some entities

[40] *Id. See also* Technical Reference Document at p. 12.

[41] NERC Comments at 5–6.

[42] NERC also suggests that Requirement R8 of TPL–001–2 supports the communication of IROLs by transmission operators to transmission owners. Proposed Reliability Standard TPL–001–2 has not been approved as a mandatory Reliability Standard.

[43] *See* NERC Comments at 5–6.

identify seasonal IROLs and we expect sub-200 kV elements of seasonal IROLs to be subject to FAC–003–2.[44] In contrast, as suggested by Idaho Power, if, for example, a multiple contingency results in the operation of the system in an unknown state for a limited period of time, a transmission owner is not responsible for compliance with FAC–003–2 with respect to IROLs that may result from temporary operation in that unknown state. We believe that this approach provides consistency and predictability in identifying the sub-200 kV transmission lines that are subject to compliance with FAC–003–2.

44. Finally, with regard to BPA's suggestion, we will not direct that NERC develop an automated electronic notification system to inform affected transmission owners of changes in IROL status. BPA may propose this directly to NERC, and NERC can determine whether this is an appropriate activity.

2. Coverage of Lines That Have an Impact on Reliability

Comments

45. NERC maintains that, consistent with Order No. 693, it has properly modified the applicability of FAC–003–2 to include transmission lines that have an impact on reliability while balancing the extension of the applicability of the standard against unreasonably increasing the burden on transmission owners.[45] According to NERC, rather than employing a bright-line threshold of 100 kV, the standard drafting team chose to limit sub-200 kV applicability to ''specific cases where lines are critical to reliability by virtue of their inclusion as elements in the determination of an IROL or a part of a Major WECC Transfer Path.'' [46] NERC states that, by relying on IROL and Major WECC Transfer Path identification as a ''proxy'' for reliability importance, FAC–003–2 uses an ''impact-based approach'' for determining applicability. Similarly, Duke asserts that FAC–003–2 appropriately covers lines that have an impact on reliability by including sub-200 kV lines that are either an element of an IROL or a major WECC Transfer Path.

46. PacifiCorp and NESCOE comment that FAC–003–2 appropriately balances the inclusion of certain sub 200-kV lines based on IROLs with the risk of over-capturing elements that do not present a risk of cascading outages. NESCOE states that this balance ''takes into account the burden placed on transmission owners and, implicitly costs ultimately borne by consumers.'' [47]

47. In response to the NOPR question regarding how NERC will assure that IROLs are properly designated in light of the 2011 Southwest Outage, NERC states that it will continue to enforce FAC–014 and FAC–010 to ensure that planning coordinators identify IROLs using their developed methodology. NERC also states that efforts are underway to implement recommendations of the Outage Report addressing the failure to properly designate IROLs.

Commission Determination

48. The Commission accepts NERC's explanation that it has properly modified the applicability of FAC–003–2 to include transmission lines that have an impact on reliability. We agree with NERC that, by making the applicability of sub-200 kV transmission lines dependent on operating impacts, *i.e.,* elements of IROLs and Major WECC Transfer Paths, the Reliability Standard reasonably balances enhanced applicability of the standard with unreasonably increasing the burden on transmission owners without commensurate reliability gains.

49. With regard to the Commission's question in the NOPR regarding how NERC will assure that IROLs are properly designated in light of the 2011 Southwest Outage,[48] we are satisfied with NERC's explanation that (a) NERC will continue to enforce FAC–014 and FAC–010 to ensure that planning coordinators identify IROLs using their developed methodology and (b) efforts are underway to implement recommendations of the Outage Report addressing the failure to properly designate IROLs.

C. Requirements R1 and R2

1. Minimum Clearance Values

NOPR Proposal

50. In the NOPR, the Commission stated that ''[b]ased on the record in this proceeding, the application of the Gallet equation appears to be one reasonable method to calculate MVCD values.'' [49] The Commission further stated that NERC ''has supported the inputs and assumptions it used to develop those minimum clearance distances, at least until such time that empirical data is developed and is available for use in setting MVCDs.'' [50] The Commission, however, explained that it remained concerned over the lack of empirical data with regard to actual flashover distances observed through testing or analysis of flashover events.[51]

51. NERC, in its petition, indicated that Electric Power Research Institute (EPRI) is planning to undertake field tests of energized high voltage conductor flash-over to vegetation, and the NOPR asked for information on the status of the testing. In the NOPR, the Commission proposed to direct that NERC conduct or commission testing to obtain empirical data and submit a report to the Commission providing the results of the testing.

Comments

52. EPRI, in its comments, provides an update on the status of its testing. EPRI states that, beginning in June 2009, it planted vegetation on a test right-of-way at EPRI's facilities, intended for high voltage air gap spark-over research. EPRI explains that it can raise and lower the test line, and adjust the test line voltage, to create the desired spark-over scenario. According to EPRI, with appropriate funding and designation of scope, testing can begin in the summer of 2013. EPRI recommends that a study designed to improve understanding of gap flash over to trees should focus primarily on validation of the Gallet equation, and specifically the flashover characteristics of a conductor to a grounded rod. EPRI states that it is committed to working with the Commission and other entities to develop an appropriate project scope, to estimate the required funding and solicit that funding.

53. NERC asks that, due to uncertainty in timing, funding, design, scope and execution of a study to develop empirical data, the Commission refrain from issuing a directive that NERC conduct or commission testing. NERC suggests that, as an alternative, the Commission ''accept NERC's commitment'' to work with the Commission and other entities to determine ''whether and how a study could be conducted to obtain the empirical data the Commission seeks * * *'' [52] According to NERC, this alternative approach would allow NERC

[44] Most likely, transmission owners do not manage vegetation under or near a line seasonally as it moves in/out of IROL status, and instead do so on a year-round basis. In other words, as a practical matter, a seasonal IROL is maintained throughout the year.

[45] NERC Comments at 8. NERC notes that the Commission in Order No. 693 directed NERC to ''modify the Reliability Standard to apply to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO.'' *Id.*

[46] *Id.* at 8–9.

[47] NESCOE Comments at 6.

[48] NOPR, 141 FERC ¶ 61,046 at P 65.

[49] NOPR, 141 FERC ¶ 61,046 at P 71.

[50] NOPR, 141 FERC ¶ 61,046 at P 66.

[51] NOPR, 141 FERC ¶ 61,046 at P 72 (citing Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 735).

[52] NERC Comments at 10.

flexibility to discuss study scope and funding with the Commission, allow for the development of partnerships in conducting the study, and allow collaboration on the study and any necessary changes to the Reliability Standard. NERC asks that, if directed to conduct empirical research, the Final Rule address (1) the need for the empirical data and scope of the study, (2) time frame for the study—and allow NERC to submit a proposed schedule for completion, and (3) funding of the study.

54. Trade Associations support EPRI conducting research ''to the extent needed,'' and submitting a preliminary report with initial observations by first quarter 2014. Trade Associations state that EPRI has the skills and equipment necessary to conduct testing, but add that funding ''may be a challenge'' since EPRI does not have a dedicated funding source. Trade Associations comment that there needs to be a clearer understanding of the scope and timeline for the research, and urge limiting the scope and subsequent report to validating the ''gap factors'' used to represent the ''air gap'' between a conductor and vegetation. Trade Associations, as well as Duke, advocate that the study not focus on validating the appropriateness of the Gallet equation for use in determining MVCDs, as that testing and validation has already taken place. Trade Associations add that, as an alternative to a Commission directive, the Commission could consider informal discussions with NERC and stakeholders to inform decisions on the scope and timing of the research, and how to most effectively ensure strong project management and funding.

55. AEP, BPA, Duke, Idaho Power and PacifiCorp also support the proposal to direct testing of the MVCDs calculated by the Gallet equations, and support EPRI conducting such field testing or research. Idaho Power recommends directing that NERC submit a report within one year of a final rule approving FAC–003–2. AEP, however, believes that it would be premature to impose a schedule for the testing until funding is procured.

56. On a related matter, regarding compliance with MVCD values in Requirements R1 and R2, PacifiCorp and APS comment that the only way to prove that the MVCD has not been violated under all rated conditions and all sag/sway scenarios is to employ Light Detection and Ranging (LiDAR) on a continuous basis. PacifiCorp recommends that, because this approach is cost prohibitive, FAC–003–2 should be revised in a subsequent version to return to the language of the Version 1 standard that allows transmission owners to remedy Clearance 2 encroachments prior to an outage without a violation. APS requests clarification regarding the need to demonstrate compliance at all rated conditions so that transmission owners can design their vegetation management plans appropriately and reduce the risk of violation.

57. APS comments that, while the Gallet equation appears to be a reasonable method to calculate MVCD values, it shares the Commission's concern regarding the lack of empirical data on actual flashover distances and supports the proposed directive for field tests of energized high voltage conductor flashover to vegetation. APS suggests that the United States Department of Energy (DOE) conduct the study, with a completion date of first quarter 2014.

58. Moreover, APS expresses concern that FAC–003–2 does not carry over the Clearance 1 requirement set forth in the current Version 1 standard. According to APS, the requirement to maintain Clearance 1 is a primary cause of the success of the Version 1 standard in reducing vegetation-related outages. APS also states that Clearance 1 clarifies that federal, state, and other agencies do not have the authority or responsibility to determine clearances on rights-of-way. According to APS, Clearance 1 ''gives legitimacy'' to transmission owners in discussions with federal agencies for clearance distances that are greater than the minimum required, i.e., Clearance 2 distances. APS, therefore, advocates that the Commission either maintain the Version 1 standard or ''integrate'' a Clearance 1 requirement into FAC–003–2.

Commission Determination

59. We adopt the NOPR proposal and direct NERC to conduct or contract testing to develop empirical data regarding the flashover distances between conductors and vegetation. The data obtained from such studies should be informative of the appropriateness and accuracy of the MVCD values for various voltage ratings as set forth in FAC–003–2. While NERC can develop the specific parameters for such testing, generally, repeated application of high voltage injections into a test line under set conditions would provide evidence of sparkover events. A statistical analysis would then evaluate the test results and provide empirical evidence to support an appropriate gap factor to be applied in calculating minimum clearance distances using the Gallet equation.[53]

60. In response to Trade Associations, we are not directing NERC to reconsider use of the Gallet equation in determining MVCD values as set forth in the Reliability Standard. As we stated in the NOPR, and adopt in the Final Rule, the application of the Gallet equation appears to be one reasonable method to calculate MVCD values.[54] However, MVCD calculations based on the Gallet equation depend on certain assumptions, such as the appropriate ''gap factor.'' NERC previously indicated that it relied on a ''widely known and regarded source for determining the appropriate gap factor.'' [55] It nonetheless is clear that the gap factor NERC applied in the Gallet equation to calculate MVCD values was not based on empirical data. If such inputs into the calculation prove to be inaccurate, in a worst case scenario, flashovers from vegetation to a conductor could occur at the MVCD values identified in the Reliability Standard. While NERC's use of the Gallet equation and the resulting MVCD values are reasonable based on the information available in this docket, minimum clearance values are too important to reliability to ultimately rely on assumed inputs, and empirical testing is appropriate to confirm the values used in the equation.

61. NERC asks that we accept its commitment to move forward with the study. However, our determination that such a study is needed warrants imposing a directive for its completion. Thus, we direct NERC, within 45 days of the effective date of this Final Rule, to submit an informational filing that includes, *inter alia:* (1) A schedule for testing, (2) scope of work, (3) funding solutions, and (4) deadline for submitting a final report to the Commission on the test results (and interim reports if a multi-year study is conducted). This approach should give NERC the flexibility to consult with the Commission or its staff as well as industry members to determine the technical specifications for the required study, funding sources and timing. However, given the importance of the testing set forth in our determination, the filing and schedule must include a reasonable date for the submission of a final report on the results of the empirical study.

62. With regard to the comments of PacifiCorp and APS on compliance with

[53] We will not specify that NERC retain EPRI or any other particular entity to conduct the required testing.

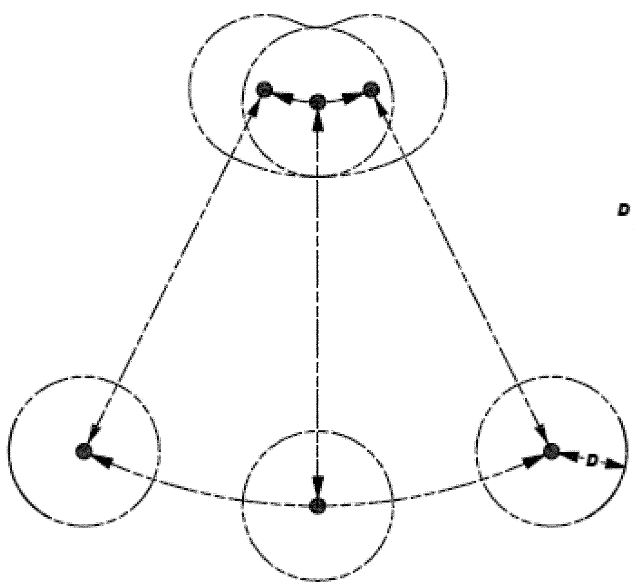
[54] NOPR, 141 FERC ¶ 61,046 at P 71.

[55] *See* NOPR, 141 FERC ¶ 61,046 at P 47.

the MVCD values under all rated conditions, we disagree that FAC–003–2 should be revised to allow transmission owners to remedy MVCD encroachments prior to an outage without a violation. NERC indicates that, under FAC–003–2, transmission operators will manage vegetation to distances beyond the MVCD to ensure no encroachment into the MVCD.[56] Thus, in response to PacifiCorp and APS, a vegetation management strategy required by Requirement R3 of FAC–003–2 must provide enough clearance to ensure that the MVCD will not be encroached under any conditions.

63. We are not persuaded by APS's concern that the Commission should carry over the Clearance 1 requirement to FAC–003–2. In the NOPR, the Commission provided a detailed explanation, based on the NERC petition, regarding how transmission owners are expected to comply with the clearance requirements set forth in Requirements R1 and R2 of FAC–03–2. The MVCD clearances represent only one aspect of FAC–003–2. The MVCD establishes a ''*minimum*[] required to prevent Flash-over.'' [57] Reliability Standard FAC–003–2 requires transmission owners to manage vegetation to ensure that vegetation does not encroach into the MVCD, which in turn requires transmission owners to manage vegetation to a distance further than the MVCD. For example, transmission owners are required to have documented compliance strategies, procedures, processes, or specifications under Requirement R3 to prevent encroachments into the MVCDs after taking into account sag and sway of the lines, as well as vegetative growth rates, planned control methods and frequency of inspections.[58] Similarly, under Requirement R7, a transmission owner is required to ''complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD.'' [59] As NERC has explained, the ''Transmission Owner is obligated to show detailed documentation that clearly explains their system with regard to the geography and how the Transmission Owner will execute the plan to prevent encroachment.'' [60] Further, according to the NERC petition, a transmission owner's documentation approach will generally contain certain specific elements including ''the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.'' [61] Likewise, NERC indicated that ''prudent vegetation maintenance practices dictate that substantially greater distances [than the applicable MVCD] will be achieved at time of vegetation maintenance.'' [62]

64. NERC also explained that a conductor's position in space at any point in time continuously changes in reaction to a variety of factors, such as the amount of thermal and physical loading, air temperature, wind velocity and direction, and precipitation. The following diagram is a cross-section view of a single conductor at a given point along the span that illustrates six possible conductor positions due to movement resulting from thermal and mechanical loading: [63]



NERC indicated that conductor movements must be taken into account under FAC–003–2, and that the transmission owner is required to show that its approach to vegetation management under Requirement R3 will prevent encroachments under all expected line positions.[64] Thus, a transmission owner must manage vegetation to ensure it does not encroach into the MVCD under multiple conditions.

65. Finally, as NERC explained in its Technical Reference Document, transmission owners will have to clear vegetation to levels ''well away from'' the minimum spark-over zone:

> As the conductor moves through various positions [due to thermal loading and physical loading], a spark-over zone surrounding the conductor moves with it.

[56] *See* NOPR, 141 FERC ¶ 61,046 at PP 67–70 (discussing NERC Petition and maintenance of vegetation beyond MVCD values).

[57] NERC Petition, Ex. A (Proposed Reliability Standard FAC–003–2) at 26 (Table 2—Minimum Vegetation Clearance Distances (MVCD) for Alternating Current Voltages), n. 7 (emphasis added).

[58] NOPR, 141 FERC ¶ 61,046 at P 67.

[59] Reliability Standard FAC–003–2, Requirement R7.

[60] *See* NERC Response to Data Request Q2.

[61] NOPR, 141 FERC ¶ 61,046 at P 67.

[62] *Id.* (citing NERC Petition, Ex. A (Proposed Reliability Standard FAC–003–2) at 26 (Table 2—Minimum Vegetation Clearance Distances (MVCD) for Alternating Current Voltages), n. 7).

[63] NERC Petition, Ex. A at 20–21.

[64] *See id.* and Requirement R3 of FAC–003–2; *see also* NERC Petition, Ex. I (Technical Reference Document) at 20–29.

* * * At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.

* * * * *

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above.[65]

66. Thus, while clearances required at the time of maintenance may vary from one region or area to another, our proposed approval of FAC–003–2 is based on our understanding, which is drawn directly from NERC's statements in its petition, that transmission operators will manage vegetation to distances beyond the MVCD to ensure no encroachment into the MVCD.

67. NERC's approach to setting MVCDs and maintaining vegetation is reasonable and designed to provide flexibility while assuring that transmission owners will proactively avoid encroachments into the MVCD. Accordingly, we will not require the reinstatement of a Clearance 1 requirement in FAC–003–2 as requested by APS.

2. Violation Risk Factor for Requirement R2

NOPR Proposal

68. The NOPR explained that NERC proposes to assign a ''high'' Violation Risk Factor to Requirement R1, which requires transmission owners to ''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.'' Requirement R2, which is assigned a ''medium'' Violation Risk Factor, provides that ''[e]ach 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.'' [66] The Commission observed that the substantive obligations set forth in Requirements R1 and R2 are identical, but the Violation Risk Factors differ based on whether a transmission line is an element of an IROL or Major WECC Transfer Path.

69. The Commission, in the NOPR, questioned whether this proposed ''bifurcation'' comported with the definition of ''medium'' Violation Risk Factor and the Commission's guidelines for reviewing Violation Risk Factor designations. The Commission also noted that transmission lines not designated as elements of IROLs played a role in past cascading outages. For these reasons, the Commission proposed to modify the Violation Risk Factor for Requirement R2 from ''medium'' to ''high,'' and invited NERC to ''provide additional explanation * * * to demonstrate the lines identified in Requirement R2 are properly assigned a medium Violation Risk Factor.'' [67]

Comments

70. NERC comments that it ''does not have additional information beyond the information supplied in its petition'' on this issue.[68] NERC maintains that the ''medium'' designation is appropriate, aligns with the definitions for Violation Risk Factors and complies with the Commission's guidelines for such designations. According to NERC, the separate designations for Requirements R1 and R2 recognize that an element of an IROL or WECC Major Transfer Path is a ''greater risk'' to the transmission system, while applicable lines that are not an element of an IROL or Major WECC Transfer Path ''do require effective vegetation management, but these lines are comparatively less operationally significant.'' [69]

71. Trade Associations ''do not disagree'' with the NOPR statement that lines not designated as IROL or Major WECC Transfer Path may be associated with higher-risk consequences including cascading outages. Trade Associations, however, maintain that the test for a medium Violation Risk Factor ''is not whether a violation could lead to system instability, but whether it is likely (or unlikely) to occur.'' [70] Thus, Trade Associations argue that the ''medium'' designation for Requirement R2 is appropriate because lines that are not an element of an IROL or Major WECC Transfer Path present a ''comparatively reduced risk'' for cascading outages or system instability. Trade Associations note that the Violation Risk Factor distinction between Requirements R1 and R2 received broad industry support and that the Commission's proposal would reverse NERC and industry's consensus approach to the development of FAC–003–2.

72. Duke and Manitoba Hydro also oppose the designation of a ''high'' Violation Risk Factor for Requirement R2. Duke notes that the definition of IROL is ''a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages * * *'' and, thus, argues that a non-IROL line does not present as great a risk for cascading outages or instability and should have a lesser Violation Risk Factor.

Commission Determination

73. We adopt our NOPR proposal and direct NERC to modify the Violation Risk Factor for Requirement R2 from ''medium'' to ''high,'' within 45 days of the effective date of the Final Rule.

74. The Commission-approved definition of a ''medium'' risk requirement is:

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is *unlikely to lead to bulk electric system instability, separation, or cascading failures* * * *. [71]

The definition of a high Violation Risk Factor is:

A requirement that, if violated, *could directly cause or contribute to* bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures * * *.[72]

75. We are not persuaded by the response of NERC and others that a medium Violation Risk Factor designation for Requirement R2 is supported because there is a relatively greater risk of cascading outages associated with a transmission line that is an element of an IROL or Major WECC Transfer Path than with a line that is not. The definition of ''medium'' Violation Risk Factor provides in part that ''violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.'' In the NOPR, the Commission questioned NERC's rationale, stating that ''NERC does not explain *why* outages on these relatively high voltage lines (200 kV or higher) would not likely lead to cascading, separation, or instability * * *'' [73] Further, the Commission pointed out that transmission lines not designated as an IROL element (or the equivalent) have been instrumental in causing major blackouts, including the August 2003

[65] NERC Petition, Ex. I (Technical Reference Document) at 21–24.

[66] Reliability Standard FAC–003–2, Requirement R2 (emphasis in original).

[67] NOPR, 141 FERC ¶ 61,046 at P 81.

[68] NERC Comments at 13.

[69] NERC Comments at 13.

[70] Trade Association Comments at 5.

[71] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145 at P 9, *order on compliance,* 121 FERC ¶ 61,179, at n.2, App. A (2007) (emphasis added).

[72] *Id.* (emphasis added).

[73] NOPR, 141 FERC ¶ 61,046 at P 77.

Northeast blackout and an August 10, 1996 blackout in the Western Interconnection.[74] Rather than responding to the Commission's request for an explanation of why outages on high voltage, non-IROL lines are unlikely to lead to instability, separation or cascading, NERC and others simply reiterate their previous rationale. Thus, we conclude that NERC and other commenters have not adequately supported a ''medium'' Violation Risk Factor designation for Requirement R2.

76. As noted above, a high Violation Risk Factor is defined, in part, as a ''requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures * * *'' As we explained in the NOPR, transmission lines that are not an element of an IROL or Major WECC Transfer Path have contributed to major cascading outages.[75] This fact supports a ''high'' Violation Risk Factor designation for Requirement R2. Moreover, our Violation Risk Factor guidelines, which require, among other things, consistency within a Reliability Standard (guideline 2) and consistency between requirements that have similar reliability objectives (guideline 3), also support modifying the Violation Risk Factor assigned to Requirement R2 from medium to high.[76]

77. Accordingly, we direct NERC to modify the Violation Risk Factor for Requirement R2 from ''medium'' to ''high,'' within 45 days of the effective date of the Final Rule.

3. *Requirements R1 and R2, Footnote 2—Conditions Outside the Transmission Owner's Control*

78. Reliability Standard FAC–003–2 includes a footnote describing certain conditions or scenarios, outside the transmission owner's control, in which an encroachment would be exempt from Requirements R1 and R2, including natural disasters and certain human or animal activity.[77] In its Petition, NERC explained, the footnote ''does not exempt the Transmission Owner from responsibility for encroachments caused by activities performed by their own employees or contractors, but it does exempt them from responsibility when other human activities, animal activities, or other environmental conditions outside their control lead to an encroachment that otherwise would not have occurred.''[78]

Comments

79. Southern Companies and PG&E disagree with the explanation of footnote 2 in NERC's petition. According to Southern Companies, NERC's ''interpretation'' is contrary to the plain language of the footnote, which unambiguously states that Requirement R1 ''does not apply to circumstances that are beyond the control of the Transmission Owner'' including ''human activity'' such as installation, removal, or digging of vegetation. Southern Companies asserts that the standard drafting team intended footnote 2, in part, to maintain the exemption from responsibility for contractor-caused violations provided under the Version 1 standard. Southern Companies argue that NERC's understanding could discourage transmission owners from having contractors remove danger trees from outside of the right-of-way that could make contact with a conductor since the transmission owner would be responsible for inadvertent contact during such removal. PG&E makes similar arguments and adds that, while recognizing that it has a responsibility to ensure that its employees and contractors are properly trained and follow appropriate safety practices, a utility cannot craft a vegetation management program that will prevent unintended and unpredictable encroachment associated with possible human activity or error. Thus, Southern Companies and PG&E urge the Commission to reject NERC's explanation of footnote 2.

80. BPA comments that it ''understand and accepts'' that transmission owners will be held liable for the actions of its employees and contractors, but believes there should be exceptions to this liability in some circumstances. According to BPA, if for example employees or contractors are negligent while felling a tree, the utility should be held accountable. However, BPA maintains that ''an exemption should be granted'' if a transmission owner can demonstrate that it utilized appropriate best management vegetation strategies and practices, but an unpredictable event occurs, such as an equipment failure, rope breakage or a hidden tree defect, and results in an encroachment that violates Requirement R1 or R2. BPA notes that placing liability on the transmission owner will have potentially significant cost impacts. For example, BPA asserts that vegetation contractors will have to increase the amounts on their liability insurance and performance bonds, and pass those costs on to transmission owners.

81. In reply to Southern Companies and PG&E, NERC states that it consulted with the standard drafting team in preparing the petition and confirmed that the intent of footnote 2 was not to exclude the activity of the employee or contractor. According to NERC, interpreting the footnote as suggested by Southern Companies and PG&E would insulate all errors in executing vegetation management plans and ''effectively encourage mismanagement.'' Rather, according to NERC, specific instances of error by employees or contractors in executing a vegetation management plan may be addressed on a case-by-case analysis, including the scenarios described by BPA.

Commission Determination

82. The language in footnote 2 of FAC–003–2 provides:

> This requirement does not apply to circumstances that are beyond the control of 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 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.

83. The stated intent of the footnote is to not hold transmission owners responsible for vegetation encroachments into the MVCD resulting from circumstances beyond the control of the transmission owner. The footnote then provides numerous examples of circumstances beyond a transmission owner's control, including ''human or animal activity such as logging * * * or installation, removal, or digging of vegetation.'' As stated above, NERC explained that footnote 2 ''does not exempt the Transmission Owner from responsibility for encroachments caused by activities performed by their own employees or contractors, but it does exempt them from responsibility when other human activities, animal activities, or other environmental conditions outside their control lead to

[74] *Id.* at PP 78–79.

[75] NOPR, 141 FERC ¶ 61,046 at P 78–79.

[76] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145 at P 16.

[77] *See* Reliability Standard FAC–003–2, n.2.

[78] NERC Petition at 23.

an encroachment that otherwise would not have occurred.'' [79]

84. We do not read NERC's statement as inconsistent with the language of the footnote, as suggested by Southern Companies. Footnote 2 does not remove from the responsibility of the transmission owner all activity of its employees or contractors under all circumstances. We do not read NERC's statement as ascribing transmission owner responsibility under Requirements R1 and R2 to all activity of its employees or contractors. Rather, should an encroachment occur as a result of activity by a transmission owner's employee or contractor, a case-by-case analysis is necessary to determine responsibility. This understanding is consistent with BPA's comments, which recognize that transmission owners may be held liable for the actions of an employee or contractor, while also acknowledging that unpredictable events may occur that are reasonably outside the control of the transmission owner. We believe that this is an appropriate approach that is consistent with the text of footnote 2 of FAC–003–2 as well as NERC's explanation of this provision.

4. Elimination of Training Requirement

85. Requirement R1.3 of the Version 1 standard provides that ''[a]ll personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties * * *'' Reliability Standard FAC–003–2 does not include a training requirement. According to NERC, the provision of the Version 1 standard is ''effectively meaningless,'' since ''appropriate'' qualifications and training are undefined and left entirely to the discretion of the transmission owner.[80]

Comments

86. PA PUC disagrees with the elimination of the training provision and recommends that the Commission require NERC to develop a standard that specifies the minimum necessary qualifications and training for personnel involved in the design and implementation of vegetation management programs. Washington DNR also urges the Commission to not approve the elimination of Requirement R1.3 and, rather, define appropriate qualifications for personnel performing vegetation management.

Commission Determination

87. We are not persuaded by the commenters to direct NERC to include a training or qualifications provision in FAC–003–2. NERC explained in its petition that the qualifications provision of the Version 1 standard, Requirement R1.3, is ''effectively meaningless,'' since ''appropriate'' qualifications and training are undefined and left entirely to the discretion of the transmission owner.[81] The use of the term ''appropriate'' in current Requirement R1.3 does not render this requirement unenforceable. However, if interested entities wish to pursue development of a future training requirement further with NERC, they can develop a Standards Authorization Request (SAR) and submit it to NERC for consideration.

D. Requirements R1 and R2

1. Consolidation of Reference Material

NOPR Proposal

88. The Commission, in the NOPR, noted that NERC provided information from several sources that are useful to an overall understanding of the intent of FAC–003–2 and how it will be enforced, including information from NERC's petition, NERC's Guideline and Technical Basis document, and NERC's May 25, 2012 response to Commission staff data requests. The NOPR requested comment on whether NERC should consolidate the reference material so that entities that must comply can find these materials in one place.[82]

Comments

89. NERC comments that it does not object to consolidating the reference material and posting it on the NERC Web site along with FAC–003–2 prior to implementation. BPA and ITC Companies agree that the reference material should be consolidated in one place. Trade Associations comment that the guidance material can have value to inform a company in developing management plans and activities, but cautions that such guidance must not alter the requirements of a Reliability Standard or be used as a compliance measurement.

Commission Determination

90. NERC and other commenters support the NOPR proposal to consolidate reference material pertaining to FAC–003–2 to support implementation of the Reliability Standard. We agree with NERC and other commenters and adopt our NOPR proposal. Accordingly, within 45 days of the effective date of the Final Rule, NERC must consolidate the reference material and post it on the NERC Web site along with Reliability Standard FAC–003–2.

2. Requirement R4—Notification of a Vegetation Condition Likely To Cause an Imminent Fault

NOPR Proposal

91. Requirement R4 of FAC–003–2 requires transmission owners to notify ''without intentional time delay'' the control center with switching authority for the applicable line when the transmission owner has confirmed the existence of a vegetation condition that is likely to cause an imminent fault. In the NOPR, the Commission asked for comment on how NERC ''would or should treat a delay in communication caused by the negligence of the transmission owner or one of its employees, where the delay may be significant and 'unintentional.' '' [83]

Comments

92. NERC responds that the specific facts and circumstances underlying a delay in communication must be determined on a case-by-case basis. However, according to NERC, the expectation in Requirement R4 is that once the transmission owner has confirmed the existence of a vegetation condition that is likely to cause an imminent fault, the transmission owner must immediately notify the control center. NERC explains that the standard drafting team did not include a ''quantitative'' time element for notification in Requirement R4 due to the difficulty in determining one time period that applies to all situations.

93. Trade Associations, Duke and Southern Companies comment that the inquiry into whether a transmission owner's notification occurred ''without any intentional time delay'' is a fact specific determination. Southern Companies adds that the drafting team considered a specific time window for notifying the control center but adopted the current language because it (i) avoids an arbitrarily narrow time-frame and (ii) provides a clear metric. PacifiCorp comments that, because the severity of an event will ''vary across facts and circumstances,'' it recommends the ''development of a load factor above which the failure to promptly report a vegetation condition * * * would warrant a high severity level and below which would warrant a lesser severity level.'' [84] Idaho Power comments that the cause of the delay

[79] NERC Petition at 23.

[80] NOPR, 141 FERC ¶ 61,046 at P 33 (citing NERC Petition at 31–32).

[81] NERC Petition at 23–24.

[82] NOPR, 141 FERC ¶ 61,046 at P 91.

[83] NOPR, 141 FERC ¶ 61,046 at P 92.

[84] PacifiCorp Comments at 5.

must be assessed and degrees of failure could be addressed in Violation Severity Levels or, if delays result from administrative process issues, addressed in the ''find, fix and track'' process.

Commission Determination

94. We agree with the explanation of NERC and Trade Associations that the specific facts and circumstances underlying a delay in communication must be determined on a case-by-case basis. We also agree with, and adopt, NERC's explanation that, pursuant to Requirement R4, once the transmission owner has confirmed the existence of a vegetation condition that is likely to cause an imminent fault, the transmission owner must immediately notify the control center.

95. We reject PacifiCorp's suggestion that severity levels for non-compliance with Requirement R4 be tied to a load factor. This appears to be an overly-complex approach to address a failure to promptly communicate a vegetation condition that is likely to cause an imminent fault.

3. Reporting Requirements

NOPR Proposal

96. The Version 1 Standard, FAC–003–1, Requirements R3 and R4, require quarterly reporting to the Regional Entities of sustained transmission outages caused by vegetation. In the NOPR, the Commission explained that, while FAC–003–2 moves the reporting requirements to the ''Additional Compliance Information'' section as a Periodic Data Submittal, NERC maintains that the reporting requirements remain enforceable under NERC's Rules of Procedure. In its Petition, NERC stated that it and Regional Entities can require entities to provide ''such information as is necessary to monitor compliance with the reliability standards'' under Section 401.3 of NERC's Rules of Procedure.[85] NERC asserted that ''it has certain courses of action it may undertake as necessary to ensure the entity complies with the Rule, pursuant to NERC Rule of Procedure Section 100, including notifying the Commission of the entity's failure to comply.[86] While agreeing that, pursuant to Section 401.3, NERC and the Regional Entities can require transmission owners to submit quarterly reports of sustained transmission outages, the Commission asked for comment regarding the ''courses of action'' that are available to NERC to ensure compliance.

Comments

97. NERC responds that, as an example of a course of action, the NERC Rules of Procedure provide possible consequences for an entity's failure to timely provide requested data—including application of a ''severe'' Violation Severity Level for a Reliability Standard Violation.[87] Idaho Power suggests that other courses of action could include Regional Entity audits, spot checks and investigations of vegetation-caused outages.

98. Santa Clara asserts that non-compliance with the quarterly reporting requirement is analogous to non-compliance with a NERC request for data that is necessary to meet NERC's section 215 obligations, pursuant to Section 1600 of NERC's Rules of Procedure. Santa Clara thus maintains that NERC's only recourse, pursuant to Section 1603 of NERC's Rules, is to refer such non-compliance to the Commission for enforcement. According to Santa Clara, the Rules provisions cited in NERC's Petition and the NOPR are not applicable because they pertain specifically to NERC's compliance/enforcement program.

99. In a reply comment, NERC reiterates its authority under Section 400 of the NERC Rules of Procedure, claiming that the quarterly reporting obligation is ''squarely'' part of NERC's compliance, monitoring and enforcement functions.

Commission Determination

100. We accept NERC's explanation that it has ''tools'' to address non-compliance with the reporting requirements set forth in the ''Additional Compliance Information'' section of Reliability Standard FAC–003–2. As NERC indicates, in connection with a substantive violation of Requirements R1 or R2 of FAC–003–2 due to an encroachment that causes a sustained outage, NERC or a Regional Entity can attach a higher Violation Severity Level to that violation based on the failure to identify the encroachment in a required periodic report. Likewise, pursuant to the NERC Rules, the Regional Entity can devote more compliance resources to oversight of an entity that fails to comply with a reporting requirement.[88]

101. We are not persuaded by Santa Clara's claims that NERC's ''tools'' do not apply because they pertain specifically to NERC's compliance/enforcement program. Rather, it is reasonable to view a transmission owner's failure to provide quarterly data as set forth in the Additional Compliance Information provision of FAC–003–2 as fitting within NERC's compliance, monitoring and enforcement function. The reporting of sustained outages caused by vegetation encroachment pertains to substantive compliance with the requirements of FAC–003–2 and will provide information that is necessary to monitor compliance with FAC–003–2 to the extent that transmission owners do not otherwise self-report possible violations. Thus, we find that the reporting of quarterly data set forth in the Additional Compliance Information provision falls within Section 401.3 of NERC's Rules of Procedure. Moreover, NERC's ''tool'' of assigning a higher violation severity level for a related violation of FAC–003–2 will occur in a compliance posture. The other ''tool'' identified by NERC, more stringent oversight of an entity that fails to comply with a reporting requirement, is simply a matter of Regional Entity discretion regarding how it chooses to apply compliance resources.

102. Ultimately, if these tools prove ineffective in gaining the cooperation of a transmission owner in timely reporting of sustained outages as set forth in FAC–003–2, NERC's Rules of Procedure provide for NERC seeking enforcement action by the Commission for a violation of NERC's Rules of Procedure. Such a violation would also violate section 39.2 of the Commission's regulations.[89]

E. Definition of Right-of-Way

103. NERC modified the definition of ''Right-of-Way'' as follows:

> 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

[85] NOPR, 141 FERC ¶ 61,046 at P 93. Section 401.3 of NERC's Rules of Procedure provides, ''all Bulk Power System owners, operators and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards.''

[86] Id. (citing NERC Petition at 31–32. Section 100 of NERC's Rules of Procedure provides, ''[e]ach Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities* * *. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify [the Commission] and take such other actions as NERC deems appropriate to address the situation.'')

[87] NERC Comments at 16 (citing NERC Rules of Procedure, App. 4C (Compliance Monitoring and Enforcement Program), at Att. 1).

[88] *See North American Electric Reliability Corp.*, 141 FERC ¶ 61,241, at PP 78–83 (2012) (approving NERC's revised Rules of Procedure, including Section 3.0 and CMEP Attachment 1 that specifies possible actions in response to an entity that fails to provide timely responses to an ERO or Regional Entity data request).

[89] 18 CFR 39.2 (2012).

records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

104. While the Commission in the NOPR proposed to approve the right-of-way definition, it also sought comment on certain aspects of the definition. Below, we discuss the following matters related to the right-of-way definition: (1) Guidance for defining an appropriate right-of-way; (2) NERC's approach to fall-ins by ''danger trees''; and (3) vegetation management strategies.

1. Guidance for Defining an Appropriate Right-of-Way

NOPR

105. In the NOPR, the Commission observed that, because fall-ins, blow-ins and grow-ins that cause a sustained outage violate FAC–003–2 only if they occur from inside the right-of-way, transmission owners have an incentive to define right-of-way as narrowly as possible to limit penalty exposure.[90] Related, the Commission noted that the right-of-way definition includes guidance as to how the transmission owner may define its right-of-way, requiring that it be based on construction documents, pre-2007 vegetation maintenance records, or as-built blowout standards. The Commission asked for comment on how the guidance in the definition will be used by (1) transmission owners to establish criteria to determine an appropriate right-of-way and (2) auditors to establish criteria to determine compliance with the Reliability Standard.[91]

Comments

106. NERC points out that ''an encroachment due to vegetation *growth* into the MVCD that caused a vegetation-related Sustained Outage'' would violate Requirements R1 and R2, ''regardless of the defined right-of-way.'' [92] NERC also comments that, given the significant cost and public scrutiny of a sustained outage, transmission owners have an incentive to set right-of-way widths properly to ensure that the land needed to operate a transmission line is included.

107. Further, NERC clarifies that the right-of-way definition requires that the width of a corridor ''be 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.'' [93] NERC thus explains that the three types of information identified in the right-of-way definition are the criteria for a transmission owner to set the width of the right-of-way using sound engineering or construction standards. NERC states that ''in all cases'' the width of the right-of-way must meet engineering or construction standards and cannot be arbitrarily set by the transmission owner. According to NERC, auditors will be able to request supporting information used to set the width of the right-of-way, including any of the available information listed in the right-of-way definition.

108. Duke comments that the Commission's concern is unfounded because transmission owners are not free to arbitrarily define a particular right-of-way but, rather, are bounded by the specific parameters stated in NERC's definition.

109. Trade Associations state that, in many instances, transmission owners may not have construction documents, pre-2007 vegetation maintenance records, or as-built blowout standards since many transmission lines were constructed decades ago and the guidance material is no longer available. Trade Associations ask the Commission to clarify that, when guidance materials are unavailable, a transmission owner may work with NERC and its Regional Entity on a case-by-case basis to develop right-of-way widths applying, for example, recognized industry procedures. AEP comments that it supports the right-of-way definition with the understanding that, for some lines, the right-of-way may be constrained by the original design or existing legal rights. ITC also supports clarification where the materials stated in the right-of-way definition are not available, and proposes specific language to insert within the definition that would require the transmission owner to develop a written procedure to determine and document the corridor width based on current industry accepted methods.

110. In its reply comments, NERC opposes ITC's proposal for specific changes to the right-of-way definition, contending that the definition includes the necessary latitude for a transmission owner to determine a right-of-way based on the options provided in the definition.

Commission Determination

111. We agree with NERC that an encroachment due to vegetation growth into the MVCD that results in a sustained outage would violate Requirements R1 and R2 regardless of the defined right-of-way. This responsibility is stated explicitly and without qualification regarding tree location: ''[e]ach Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) * * * of the types shown below * * * (4) An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.'' [94] Further, we agree with NERC and others that the criteria set forth in the right-of-way definition provide a reasonable, objective means of determining an appropriate right-of-way width.

112. With regard to the concern of Trade Associations and others where none of the records mentioned in the right-of-way definition are available for a specific applicable transmission line, an alternative approach to setting right-of-way width is necessary. We agree with NERC that ''in all cases'' the width of the right-of-way must meet engineering or construction standards and cannot be arbitrarily set by the transmission owner. As suggested by Trade Associations, one reasonable way to achieve this is for the transmission owner to work with NERC and the relevant Regional Entity on a case-by-case basis to develop right-of-way widths applying recognized industry procedures. Further, NERC may determine—after some experience with setting right-of-way widths—that this is an appropriate topic for an industry advisory or operating committee guideline. We will not, however, require that NERC revise the Reliability Standard to address this issue, as suggested by ITC.

2. NERC Approach to Fall-Ins by ''Danger Trees''

NOPR

113. In the NOPR, the Commission agreed with NERC that fall-ins of green or healthy trees outside the corridor-based right-of-way, but within the right-of-way controlled by the transmission owner, would not violate FAC–003–2. The Commission, however, questioned NERC's approach to a fall-in by ''danger timber'' in that same range. NERC explained that, ''if the TO is regularly identifying its danger trees and has a program for managing the risk of fall-in

[90] NOPR, 141 FERC ¶ 61,046 at P 97.

[91] NOPR, 141 FERC ¶ 61,046 at P 102.

[92] NERC Comments at 16–17 (emphasis in original) (citing Reliability Standard FAC–003–2, Requirements R1(4) and R2(4)).

[93] NERC Comments at 20. *See also* BPA Comments at 5.

[94] Reliability Standard FAC–003–2, Requirement R1, subsection (4).

there would be no violation.'' [95] The Commission expressed concern that this statement ''could be read to mean that, as long as the transmission owner identifies danger trees and has a program to manage the risk of those trees, an encroachment into the MVCD from a location within the transmission owner's control would not be a violation.'') [96] The Commission disagreed with such an approach because the mere existence of a program to identify danger trees and a program to manage risk should not shield a transmission owner from enforcement.

Comments

114. In response to the Commission's concerns, NERC clarifies that its earlier statement that ''if the TO is regularly identifying its danger trees and has a program for managing the risk of fall-in there would be no violation'' is accurate so long as the transmission owner implements a well-managed and executed vegetation management program as documented under Requirement R3 and as carried out through the risk-based Requirements R6 and R7. According to NERC, the reference to ''no violation'' pertained to Requirements R6 and R7, but was not intended to convey that mere existence of a program to identify danger trees and a program to manage risk would create a shield from a finding of a violation under Requirements R1 or R2 if an encroachment occurs.

115. APS, BPA, PA PUC and VELCO support NERC's approach. They agree that the ''mere existence'' of a danger tree program is insufficient, and transmission owners should have a ''demonstrably active and robust'' danger tree management program. BPA adds that a transmission owner that has reasonably implemented a program to manage fall-in risks should be exempt from violation since ''accidents do occur'' even when due care is exercised. PA PUC comments that, while NERC's data request response is helpful, it should be incorporated into the BES definition or the Reliability Standard to prevent confusion in the future.

116. Trade Associations articulate their understanding that, in the event of encroachment into the MVCD by a danger tree located outside the right-of-way but within the control of the transmission owner, the transmission owner would not be found in violation of Requirement R6 when it implemented a program that regularly identifies danger trees and manages the risk of fall-in encompassing areas within the transmission owner's control. Further, Trade Associations comment that, while it is common practice to include identification and mitigation of danger trees in transmission owner vegetation management plans, in many cases the identification of diseased or dying trees is not a matter involving simple observation.[97] Thus, Trade Associations as well as Duke caution against basing enforcement decisions on ''post hoc'' analyses of whether a transmission owner correctly identified a dead or diseased tree. They assert that, if the Commission places transmission owners at risk of violation based on such after-the-fact assessment, transmission owners may likely engage in more clear-cutting to avoid the risk. VELCO also indicates that a strict stance on off-corridor danger tree management could lead to more clear-cutting and adds that a better outcome motivates transmission owners to actively identify and, exercising professional judgment, remove danger trees on a case-by-case basis.

117. PacifiCorp maintains that the Commission's concern appears to be unfounded based on the explicit language of Requirements R1 and R2 that require transmission owners to manage vegetation to prevent all encroachments into the MVCD of an applicable line, and then identifies specific circumstances. According to PacifiCorp, the NERC drafting team was concerned that many transmission owners have rights-of-way far wider than necessary to responsibly maintain the integrity of their applicable transmission lines. PacifiCorp asserts that it would be unreasonable to hold utilities to the same level of compliance for all activities within the legal right-of-way for areas beyond those currently necessary.

Commission Determination

118. Fall-ins of danger trees into the MVCD from outside the right-of-way but within the control of the transmission owner are not addressed by Requirements R1 and R2. However, such fall-ins do have compliance implications with regard to Requirements R6 and R7 of FAC–003–2. Requirement R6 requires each transmission owner to perform a ''Vegetation Inspection of 100% of its applicable transmission lines * * * at least once per calendar year * * * '' NERC defines the term ''Vegetation Inspection'' as ''[t]he systematic examination of vegetation conditions on a Right-of-Way *and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s)* prior to the next planned maintenance or inspection * * * '' [98] The definition explicitly provides that the Vegetation Inspection include the examination of vegetation conditions not only in the defined right-of-way but of ''vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) * * * '' Likewise, Requirement R7 provides that ''[e]ach transmission owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD,'' without mention of or limitation to the defined right-of-way.[99]

119. Thus, the fall-in of danger tree from outside the defined right-of-way but within a transmission owner's control would likely merit examination to determine whether the transmission owner is properly conducting the annual Vegetation Inspection as required by Requirement R6 and performing the annual work plan as required by Requirement R7. In this context, we find the explanation of NERC and other commenters informative that it is not sufficient for a transmission owner simply to demonstrate that it identifies danger trees and has a program for managing the risk of fall-in. Rather, a transmission owner must have a well-managed, danger tree management program as carried out through Requirements R6 and R7.[100]

120. As indicated by NERC, the ''documented maintenance strategies'' required by Requirement R3 should demonstrate whether a transmission owner adequately inspects vegetation and completes its annual work plan. Likewise, the Measures set forth in FAC–003–2 provide the basis for determining a transmission owner's compliance with the corresponding Requirements R6 and R7. We agree with Trade Associations and Duke that a potential violation of Requirements R6 and R7 should not be based on ''post

[95] NOPR, 141 FERC ¶ 61,046 at P 101 (citing NERC Data Responses, Responses to Q9 (May 25, 2012)).

[96] NOPR, 141 FERC ¶ 61,046 at P 101.

[97] Trade Associations note that ANSI A–300 defines ''danger tree'' as ''a tree on or off the right-of-way that could contact electric supply lines''; and defines ''hazard tree'' as ''a structurally unsound tree that could strike a target when it fails.''

[98] NERC Petition at 2 (emphasis added).

[99] Reliability Standard FAC–003–2, Requirement R7. The Guideline and Technical Basis contained in FAC–003–2 also indicates that the annual work plan is not limited to the right-of-way: ''[i]n general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed.'' *Id.* at 24.

[100] NERC Comments at 19–20.

hoc'' analyses of whether a transmission owner correctly identified a dead or diseased tree. A fall-in from outside of the defined right-of-way may give reason to review a transmission owner's compliance with the annual inspection and work plan requirements. In the context of fall-ins from outside the defined right-of-way, enforcement decisions should be based on a review of the quality of the transmission owner's program and its execution of that program.

3. Vegetation Management Strategies

NOPR

121. In the NOPR, the Commission noted that FAC–003–2 does not require clear-cutting along the right-of-way but, instead, gives the transmission owner flexibility to adopt an appropriate vegetation management strategy to comply with the Reliability Standard. The NOPR also noted that NERC's Technical Reference Document provides that different vegetation management strategies may be appropriate for different areas, and FAC–003–2 gives transmission owners the option to adopt strategies to comply with FAC–003–2 that encourage active vegetation management and Integrated Vegetation Management rather than clear-cutting.[101] Further, NERC's Technical Reference Document describes American National Institute of Standards (ANSI) A–300—Best Management Practices for Tree Care Operations and identifies Integrated Vegetation Management as a best management practice, including incorporation of wire-border zone management techniques and the establishment and maintenance of compatible vegetation.

Comments

122. Trade Associations state that, since approval of FAC–003–1, transmission owners have ''aggressively pursued compliance under a 'zero defects' mandate for transmission tree-related outages'' and, as a result, only a small number of violations have affected reliable operation of the Bulk-Power System.[102] According to Trade Associations, transmission owners' vegetation management practices are designed to prevent vegetation-related outages by creating and sustaining a stable and compatible ''vegetated community'' within a transmission corridor using ''integrated vegetation management'' techniques. They further explain that vegetation that has the ''genetic disposition'' to grow to heights that may interfere with transmission should be removed. Trade Associations contend that continuous trimming will not guarantee that an encroachment will not occur, and it is a ''gamble'' not to use best management practices and remove the vegetation that will interfere with transmission. They add that transmission owners do have successful vegetation management programs that also help property owners maintain and even enhance the environmental benefits of the right-of-way while ensuring sufficient clearance between the vegetation and energized conductors. Trade Associations and ITC add that transmission owners have outreach programs and maintain information on company Web sites on vegetation management practice, and encourage the Commission to further this public education process. PacifiCorp suggests that the Commission appears to apply a ''double standard'' by supporting a zero tolerance approach to compliance with FAC–003 while also opposing tree removal.

123. PG&E and APS support the Commission's recognition of the importance of using best utility vegetation management practices, the use of Integrated Vegetation Management and the ''wire-border zone'' technique contained in ANSI A–300. PG&E states that an approach using these concepts will accomplish the objective of developing and maintaining a sustainable, low-growing compatible plant community in the right-of-way, while reducing the risk of vegetation-related outages. APS states that ANSI A–300 recognizes the need to remove vegetation that can cause power outages within the right-of-way and to convert the right-of-way to more compatible plant species.

124. APS comments that ANSI A–300 recognizes the need to communicate with all stakeholders involved in the vegetation maintenance process. APS acknowledges that the Commission ''is in a difficult position'' on ensuring reliability and considering public expectations for vegetation management.[103] APS recognizes that, in the past, transmission owners have used the Commission's regulations as an ''excuse'' for clearing trees. According to APS, while properly implementing best management practices may require clearing that could displease property owners, vegetation management programs should engage and work cooperatively with land owners.

125. Trade Associations also raise concerns regarding right-of-way access issues, particularly involving federal lands. According to Trade Associations, for some transmission owners, access to federal lands is a ''significant variable'' in setting facilities ratings, configuring transmission for reliability and vegetation management. Trade Associations assert that, particularly in Western states, transmission owners have experienced significant difficulties with federal agency field personnel for obtaining timely permission to access land and scheduling facilities inspections and maintenance activities, including vegetation management. Trade Associations thus urge the Commission to take a leadership role in initiating and coordinating discussions with other federal agencies, and with stakeholder groups, to find practical remedies to right-of-way access issues.

Commission Determination

126. As indicated by NERC, Requirement R3 documented maintenance strategies can take many forms.[104] While accommodating flexibility, these documented strategies must have sufficient specification to provide a means to follow the transmission owner's strategy through a paper trail or guidelines. Documented strategies cannot be so vague as to fail to provide any clear guidance for auditors and others to understand the basis for the transmission owner's vegetation management program.

127. With regard to comments on the implementation of vegetation management strategies, we agree that ANSI–A 300 is a commonly recognized source for best vegetation management practices. We disagree with PacifiCorp, however, that we are seeking to apply a ''double standard'' by supporting a zero tolerance approach to compliance with FAC–003 while also opposing tree removal. We understand that, as explained by Trade Associations and other commenters, best practices call for the removal of tall-growing vegetation from the right-of-way and replacement with a sustainable plant community. In many circumstances, this is a reasonable approach. However, we also believe that a transmission owner should not monolithically equate vegetation management with tree removal. Circumstances may provide greater latitude, for example, when addressing the concerns of an individual landowner and where the species of vegetation are not genetically disposed

[101] NOPR, 141 FERC ¶ 61,046 at P 100 (citing NERC Petition, Ex. I (Technical Reference Document) at 24–29).

[102] Trade Association Comments at 13. *See also* ITC Comments at 6–7.

[103] APS Comments at 8.

[104] NERC Petition at 17, 20, 35.

to encroach into the MVCD. Certainly, as recognized by APS, a transmission owner decision's to remove vegetation in such circumstances should not be ascribed to the Commission.

128. Ultimately, transmission owners should work with private land owners to determine an appropriate approach that assures reliability and respects private land owner concerns. As noted by commenters, this approach requires clear communications between transmission owners and private landowners; and meaningful outreach should indicate how a transmission owner plans to execute vegetation management along the right-of-way.

129. Trade Associations raise concerns regarding transmission owners' right-of-way access issues on public lands. We note that in Order No. 693, the Commission directed NERC ''to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.'' [105] NERC has not provided this analysis, nor does the development record provided with NERC's petition indicate that the standard drafting team utilized such analysis or data in developing FAC–003–2. In these circumstances, given the lack of objective data, it is difficult for the Commission to gauge the nature or seriousness of this issue.

130. NERC should gather and analyze the necessary data regarding vegetation management issues on public lands. If NERC's analysis indicates that there are issues that should be addressed, NERC should propose a means to address the concern, for example by issuing an alert, or propose other appropriate action.

III. Information Collection Statement

131. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[106] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

132. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act of 1995. The Commission solicited comments on the need for and the purpose of the information contained in Reliability Standard FAC–003–2 and the corresponding burden to implement the Reliability Standard. The Commission received one comment on the reporting burden estimates. Idaho Power states that it does not anticipate adding new transmission lines to its vegetation management plan and, therefore, Idaho Power does not project a significant increase in outage reporting.

133. The Final Rule approves Reliability Standard FAC–003–2, which includes certain requirements to create and maintain records related to a transmission owner's vegetation management strategies, vegetation management work plan and its performance of inspections. Because transmission owners have vegetation management plans they follow per the existing transmission vegetation management standard (FAC–003–1), and must compile and maintain similar records and provide similar reports under the existing standard, the revisions are expected to have a minor impact on the burden of record-keeping and reporting. In addition, by allowing greater flexibility compared to the currently-effective Version 1 standard with regard to the materials that must be maintained for a vegetation management plan or strategy, FAC–003–2 may reduce the reporting burden for some entities.

134. *Public Reporting Burden:* Our estimate below regarding the number of respondents is based on the NERC compliance registry as of July 24, 2012. According to the compliance registry, NERC has registered 330 transmission owners within the United States. Transmission owners must report and retain certain data pursuant to the currently effective Version 1 standard. Thus, the burden estimate below is based on the potential change in the reporting burden imposed by FAC–003–2. Requirement R3 of FAC–003–2 provides more flexibility than FAC–003–1 for transmission owners in preparing and maintaining a vegetation management program, and the incremental change in the burden may be negligible or even decrease for some portion of transmission owners. The individual burden estimates are based on each transmission owner having to perform a one-time review of the revised Reliability Standard's information collection requirements and to make any required modifications to its existing vegetation management plans and documentation procedures. In addition, the burden estimate takes into account an on-going, albeit very minor increase in the quarterly reporting burden, based on the increased burden to confirm whether or not reportable outages have occurred on lines not previously subject to FAC–003–1's requirements. Idaho Power's comment affirms that the increase in quarterly reporting burden should be insignificant. Further, the burden estimate takes into account the increased recordkeeping burden associated with the Reliability Standard's annual vegetation inspection requirements, which is estimated to increase the inspection cycles (and the associated documentation to demonstrate compliance) for about one third of transmission owners (110 transmission owners).

FAC–003–2 (transmission vegetation management)	Number of transmission owner respondents (1)	Number of responses per respondent (2)	Average burden hours per response (3)	Total annual burden hours (1) × (2) × (3)
One time review and modifications to existing documentation, plans and procedures	330	1	16	5,280 (one-time)
Quarterly Reporting	[107] 115	4	0.5	230
Annual Vegetation Inspections Documentation	110	1	2	220

[105] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 732.

[106] 5 CFR 1320.11.

FAC–003–2 (transmission vegetation management)	Number of transmission owner respondents (1)	Number of responses per respondent (2)	Average burden hours per response (3)	Total annual burden hours (1) × (2) × (3)
Total	....	....	....	5,730

[107] While approval of FAC–003–2 is not expected to increase the number of reports made or the number of reportable outages experienced, some utilities may experience a slight increase in the amount of time required to confirm whether or not any reportable outages occurred due to the increased applicability of the standard to certain sub-200 kV transmission lines.

Total Annual Hours for Collection: (Compliance/Documentation) = 5,730 hours.

Quarterly Reporting Cost for Transmission Owners: = 230 hours @ $70/hour [108] = $16,100.

Annual Vegetation Inspections Documentation: = 220 hours @ $28/hour [109] = $6,160.

Total Annual Cost (Reporting + Record Retention): = $16,100 + $6,160 = $22,260.

One-Time Review and Modification of Plans and Documentation: 5,280 hours @ $52/hour [110] = $274,560.

Title: Mandatory Reliability Standards for the Bulk-Power System.

Action: Revisions to collection FERC–725A.

OMB Control No.: 1902–0244.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: Annual, quarterly, and one-time.

Necessity of the Information: Reliability Standard FAC–003–2 Transmission Vegetation Management is part of the implementation of the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk Power System. Specifically, the revised standard would ensure that transmission owners are protecting transmission lines from encroachment of vegetation.

Internal Review: The Commission has reviewed the revisions to the currently-effective Reliability Standard and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimate associated with the information requirements.

135. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *DataClearance@ferc.gov,* phone: (202) 502–8663, fax: (202) 273–0873].

For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4638, fax: (202) 395–7285]. For security reasons, comments to OMB should be submitted by email to: *oira_submission@omb.eop.gov.* Comments submitted to OMB should include OMB Control Number 1902–0244 and Docket Number RM12–4–000.

IV. Environmental Analysis

136. The Commission is required to prepare an Environmental Assessment (EA) or an Environmental Impact Statement (EIS) for any action that may have a significant adverse effect on the human environment.[111] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. In the NOPR, the Commission stated the proposed action, i.e., approval of the revised Reliability Standard, falls within the categorical exclusion for rules that are clarifying, corrective, or procedural, or that do not substantially change the effect of the regulations being amended.[112]

Comments

137. Washington DNR urges the Commission to perform an EIS on Reliability Standard FAC–003–2. According to Washington DNR, vegetation management can conflict with protection of fragile vegetation species that are identified in federal and state programs and, thus, changes to the Reliability Standard may result in adverse environmental impacts. Washington DNR comments that it cannot fully assess the impacts of the proposed Reliability Standard since it is unaware of the locations of all transmission lines operated below 200 kV that would be subject to FAC–003–2 and may affect state lands. Washington DNR contends that the proposed Commission rulemaking constitutes a major federal action with the potential for significant impacts on the environment and must not be promulgated without an EIS. Washington DNR disagrees with the Commission's reliance on the categorical exclusion for rules that are clarifying, corrective, or procedural, or do not substantially change the effect of regulations being amended. Rather, according to Washington DNR, the proposal substantively changes the existing regulations by ''applying expanded clearance standards and an entirely new and legally indefensible definition of 'right-of-way', and does so across unpublished miles of under-200 kV line not currently subject to this regulation.'' [113]

138. Washington DNR also contends that the timeframe to comply with the Version 2 standard does not include sufficient time for transmission owners to give meaningful notice to landowners, obtain relevant information about the environmental characteristics or management of adjacent lands, obtain permits, and work with landowners to create mutually agreed upon management plans.

139. APS and PacifiCorp recommend that the Commission initiate an EIS in conjunction with other federal agencies such as the U.S. Department of Agriculture, U.S. Department of Interior and DOE. According to APS, because the Version 1 standard ''compelled transmission owners to determine what should be appropriate for vegetation

[108] This figure is the average of the salary plus benefits for a manager and an engineer. The figures are taken from the Bureau of Labor and Statistics Web site at *http://bls.gov/oes/current/naics3_221000.htm.*

[109] Wage figure is based on a Commission staff study of record retention burden.

[110] This figure is the average of the salary plus benefits for an engineer and a forester. The figures are taken from Bureau of Labor and Statistics Web site at *http://bls.gov/oes/current/naics3_221000.htm.*

[111] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[112] *See* NOPR, 141 FERC ¶ 61,046 at P 116 (citing 18 CFR 380.4(a)(2)(ii)).

[113] Washington DNR Comments at 3.

management, the industry automatically referenced ANSI A–300 Best Management Practices for Tree Care Operations.'' [114] APS claims that the elimination of a direct reference to ANSI A–300 will ''lead to weak links'' and possibly result in some transmission owners regressing in their vegetation management programs by reverting to tree pruning. Thus, APS recommends that an EIS address implementation of ANSI A–300 and applicable best management practices on federal lands to ''provide transmission owners authority and allow them to define their program of work within the scope of their TVMP and eliminate personal opinion when working at the local level of each federal agency.''[115]

Commission Determination

140. The Commission is required to prepare an EA or an EIS for any action that may have a significant adverse effect on the human environment.[116] We disagree with the assertion that we should require an EIS or EA for Reliability Standard FAC–003–2.

141. Reliability Standard FAC–003–2 modifies the currently effective Version 1 standard. For example, it includes minimum vegetation clearance distances in the text of the standard, instead of referencing another document as in the Version 1 standard. However, the revised standard makes little change in minimum clearance distance values from the current rule and, therefore, will not have a significant impact on how transmission owners currently perform vegetation management so as to warrant an EA or EIS. The differences in minimum clearance distances between FAC–003–2 and the Version 1 standard are measured in inches, and thus do not give rise to concerns that the modified standard may have a significant adverse effect on the human environment.[117]

142. Further, we are not persuaded by Washington DNR that NERC's revised definition of the term ''Right-of-Way'' justifies undertaking an EA or EIS. Version 1 defines right-of-way based on a transmission owner's legal rights.[118] In Order No. 693, the Commission directed NERC to consider whether to change the definition of right-of-way to more precisely define the area that needed to be subject to vegetation management, i.e., to encompass the required clearance area, and not the entire legal right-of-way, particularly where the legal right-of-way may greatly exceed the area needed for effective vegetation management.[119] The revised right-of-way definition submitted with FAC–003–2 recognizes that a transmission owner may not always need to maintain vegetation to the full extent of its legal right-of-way. For example, PacifiCorp explains that a transmission owner may have acquired rights in anticipation of adding facilities at a later date, but maintenance of the additional corridor may not be necessary to assure that vegetation will not encroach into existing transmission lines.[120] The new FAC–003–2 would allow transmission owners flexibility to manage vegetation in an area less than their legal right-of-way but still in an area appropriate to assure no encroachment into a transmission line. Other than pointing to the fact that NERC revised the right-of-way definition, Washington DNR provides no explanation how bringing more precision to the area that needs to be managed in the new right-of-way definition may have a significant adverse effect on the human environment.

143. The application of the standard to certain sub-200 kV facilities under the revised standard also does not warrant the preparation of an EA or EIS. While the expanded applicability subjects the owners of certain sub-200 kV transmission facilities to compliance with FAC–003–2, we do not expect the expanded applicability of FAC–003–2 to significantly change vegetation management practices at these facilities or otherwise have a significant adverse effect on the human environment. The transmission lines that are implicated by FAC–003–2, even under the expanded applicability, by necessity, are currently subject to vegetation management practices, as transmission owners must maintain their existing rights-of-way to prevent flashovers and outages.[121] In many instances, utilities manage vegetation to comply with either good utility practice or conduct vegetation management in accordance with best industry practices.[122]

144. Moreover, while the revised Reliability Standard requires a specific result, i.e., that vegetation does not encroach into the MVCD, the standard does not require any specific means of obtaining that result. Transmission owners will have flexibility regarding how they perform vegetation management to comply with the new standard, and the circumstances (topography, weather, tree growth, etc.) will differ for each transmission owner.[123] Thus, while we believe that the impacts will not be significant because transmission owners have generally conducted vegetation management on the sub-230 kV facilities that will now be subject to compliance with FAC–003–2 (or else there would have been many more flashovers and outages), identifying those incremental impacts of the revised Reliability Standard on either a programmatic or site-specific basis would be difficult and likely not produce meaningful results. In such circumstances, where the potential impacts are not subject to meaningful quantification, courts have found that it is not necessary to conduct an EIS or EA.[124]

145. Further, we are not persuaded by the claims of APS and PacifiCorp. According to APS, because the Version 1 standard ''compelled transmission owners to determine what should be appropriate for vegetation management,

[114] APS Comments at 5.

[115] *Id.* at 6.

[116] Order No. 486, FERC Stats. & Regs. ¶ 30,783.

[117] *See* May 23, 2012, NERC Comments on PNNL Report, Att. A at 5, identifying the ''additional distance afforded by MVCD'' for a 115 kV transmission line as 2.52 inches; the greatest difference shown for a 500 kV line is 14.04 inches.

[118] NERC's Version 1 ROW definition provides:

A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

[119] NOPR, 141 FERC ¶ 61,046 at P 16.

[120] PacifiCorp comments at 7.

[121] A 2004 study provided information on clearance distances maintained by utilities for sub-230 kV transmission lines. A comparison of this data with the minimum clearance distances for sub-200 kV transmission lines set forth in FAC–003–2 indicates that, historically, the vast majority of utilities have cleared vegetation to greater distances than the minimum values set forth in the standard. *See Utility Vegetation Management and Bulk Electric Reliability Report from the Federal Energy Regulatory Commission,* Sept. 2004, p. 11, Table 4 (Vertical Clearances Reported).

[122] *E.g.,* ANSI A–300—Best Management Practices for Tree Care Operations.

[123] In certain circumstances, transmission owners will negotiate the vegetation management activities they undertake to comply, also showing that the new standard does not dictate a specific means to manage vegetation. *See, e.g.,* Memorandum of Understanding Among the Edison Electric Institute and the U.S. Department of Agriculture Forest Service and the U.S. Department of the Interior Bureau of Land Management, Fish and Wildlife Service, National Park Service and the U.S. Environmental Protection Agency (2006), with the stated purpose of establishing ''a framework for developing cooperative right-of-way integrated vegetation management (IVM) practices * * *''

[124] *See, e.g., Piedmont Environmental Council* v. *FERC,* 558 F.3d 304 (4th Cir. 2009) (finding that no EIS was required for FERC rulemaking to implement FPA section 216 electric transmission line siting authority); *Northcoast Environmental Center* v. *Glickman,* 136 F.3d 669 (9th Cir. 1998) (EA was not required for cedar management plan because, while providing management goals and strategies, the plan did not propose site-specific activities or call for specific actions directly impacting the environment); *Northeast Utilities Service Co.* v. *FERC,* 993 F.2d 937 at 958–9 (1st Cir. 1993) (holding that EIS was not required for utility merger based on fact that new generating facilities might wind up in different locations than would have been the case absent the merger because that fact was not of sufficient significance and ''its significance was not quantifiable'').

the industry automatically referenced ANSI A–300 Best Management Practices for Tree Care Operations.'' [125] While the Version 1 standard references ANSI A–300, it does not require compliance with the document.[126] Moreover, FAC–003–2 references the same document, again as a source for best industry practices in vegetation management.[127] Thus, we are not persuaded by APS's claim that the change in references to ANSI A–300 will ''lead to weak links'' and possible ''regression'' in vegetation management practices, or that the revisions to the standard may result in a significant adverse effect on the human environment, let alone a substantial change to the regulation.

146. APS recommends that an EIS address implementation of ANSI A–300 and best management practices on federal lands to ''provide transmission owners authority and allow them to define their program of work * * * and eliminate personal opinion when working at the local level of each federal agency.'' [128] However, implementation of ANSI A–300 best practices is not a requirement of the Version 1 standard or FAC–003–2. Thus, we are not persuaded by APS that an EIS is required to study the implementation of ANSI A–300 best practices on federal lands.

147. For the reasons discussed above, we conclude that the Commission correctly asserted that approval of the revised Reliability Standard falls within the categorical exclusion set forth in section 380.4(a)(2)(ii) of the Commission's rules and regulations for promulgation of rules that are ''clarifying, corrective or procedural, or that do not substantively change the effect of * * * regulations being amended.'' Accordingly, we will not require an EIS or EA on Reliability Standard FAC–003–2.

V. Regulatory Flexibility Act Certification

148. The Regulatory Flexibility Act of 1980 (RFA) [129] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[130] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[131]

149. Reliability Standard FAC–003–2 applies to overhead transmission lines operated at 200 kV or higher, and, for the first time, to transmission lines operated at less than 200 kV if they are elements of an IROL or elements of a Major WECC Transfer Path. In addition, FAC–003–2 requires annual vegetation inspections for all applicable lines, which could result in an increase in annual inspections performed for a subset of transmission owners.

150. Comparison of the NERC Compliance Registry with data submitted to the Energy Information Administration on Form EIA–861 indicates that, of the 330 transmission owners in the United States registered by NERC, 127 of these entities qualify as small businesses. The Commission estimates that the 127 transmission owners that qualify as small businesses will incur increased costs associated solely with a one-time review of the standard and modification to existing plans and procedures. As described in the information collection section of this Final Rule, the estimated cost for the increased data collection and retention is approximately $1,000 per entity.

151. Further, some transmission owners that qualify as small entities will incur costs associated with an increase in frequency of inspections. As indicated above, the Version 1 standard requires periodic vegetation management inspections of transmission line rights-of-way at an interval determined by each transmission owner. Requirement R6 of FAC–003–2 requires each transmission owners to inspect 100 percent of the transmission lines at least once per year. Based on a review of available information, including data provided in response to a 2004 vegetation management study performed by Commission staff,[132] we estimate that approximately one third, i.e., 42, of the transmission owners that qualify as small entities would incur costs associated with more frequent inspection cycles. Assuming that (1) such small entities own approximately 50–200 miles of transmission lines, (2) approximately 15–20 miles of transmission line can be inspected per day and (3) cost of labor is approximately $47 per hour,[133] the estimated increase in inspection cost for these 42 small entities is in the range of approximately $5,000 to $10,000 per entity. As discussed above, FAC–003–2 modifies the applicability of the Reliability Standard to include overhead transmission lines that are operated below 200 kV if they are either an element of an IROL or an element of a Major WECC Transfer Path. Based on a review of the Major WECC Transfer Paths and a sample of sub-200 kV IROLs in the Eastern Interconnect, the Commission believes that most, if not all, of the transmission lines subject to the expanded applicability of FAC–003–2 are owned by large entities. Thus, the increased cost of the new rule to small entities appears to be negligible with respect to the expanded applicability of the Reliability Standard.

152. Based on the above analysis, the Commission does not consider the cost of the modified Reliability Standard to be a significant economic impact for small entities because it should not represent a significant percentage of an affected small entity's operating budget.

153. Based on this understanding, the Commission certifies that the Reliability Standard will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VI. Document Availability

154. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

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[125] APS Comments at 5.

[126] Reliability Standard FAC–003–1, fn 1 provides in full: ''ANSI A300, Tree Care Operations—Tree, Shrub, and Other Woody Plant Maintenance—Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.''

[127] Reliability Standard FAC–003–2, Guidelines and Technical Basis, p. 20, provides, ''[a]n example of one approach commonly used by industry [to manage vegetation] is ANSI Standard A300.''

[128] APS Comments at 6.

[129] 5 U.S.C. 601–612.

[130] 13 CFR 121.101.

[131] 13 CFR 121.201, Sector 22, Utilities & n.1.

[132] *See Utility Vegetation Management and Bulk Electric Reliability Report from the Federal Energy Regulatory Commission,* p. 8–10 (Sept. 7, 2004). *Available at: http://www.ferc.gov/industries/electric/indus-act/reliability/veg-mgmt-rpt-final.pdf.*

[133] The wage figure is taken from the Bureau of Labor and Statistics at *http://bls.gov/oes/current/naics3_221000.htm.*

155. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

156. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

VII. Effective Date and Congressional Notification

157. These regulations are effective May 28, 2013. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Note: The Appendix will not appear in the *Code of Federal Regulations.*

Appendix

Commenters

American Electric Power Service Corporation (AEP)
Arizona Public Service Company (APS)
Bonneville Power Administration (BPA)
The City of Santa Clara, California, d/b/a Silicon Valley Power (Santa Clara)
Duke Energy Corporation (Duke)
Electric Power Research Institute (EPRI)
FirstEnergy Service Company (FirstEnergy)
Idaho Power Company (Idaho Power)
International Transmission Company d/b/a/ ITC*Transmission,* Michigan Electric Transmission Company, LLC, ITC Midwest LLC and ITC Great Plains LLC (ITC Companies)
Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company, subsidiaries of Great Plains Energy, Inc. (KCPL)
Manitoba Hydro
The New England States Committee on Electricity (NESCOE)
North American Electric Reliability Corporation (NERC)
Pacific Gas and Electric Company (PG&E)
PacifiCorp
The Pennsylvania Public Utility Commission (PA PUC)
Southern Company Services, Inc., on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company (Southern Companies)
Trade Associations (jointly, Edison Electric Institute, American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and Transmission Access Policy Study Group)
Vermont Electric Power Company, Inc. (VELCO)
Washington State Department of Natural Resources (Washington DNR)

[FR Doc. 2013–07113 Filed 3–27–13; 8:45 am]

BILLING CODE 6717–01–P

SOCIAL SECURITY ADMINISTRATION

20 CFR Part 404

[Docket No. SSA–2010–0078]

RIN 0960–AH28

Revised Medical Criteria for Evaluating Visual Disorders

AGENCY: Social Security Administration.

ACTION: Final rules.

SUMMARY: We are revising and reorganizing the criteria in the Listing of Impairments (listings) that we use to evaluate cases involving visual disorders in adults and children under titles II and XVI of the Social Security Act (Act). The revisions reflect our program experience and guidance we have issued in response to adjudicator questions we have received since we last revised these criteria in 2006. These revisions will provide clarification about how we evaluate visual disorders and ensure more timely adjudication of claims in which we evaluate visual disorders that result in a loss of visual acuity or field.

DATES: These rules are effective April 29, 2013.

FOR FURTHER INFORMATION CONTACT: Cheryl A. Williams, Office of Medical Listings Improvement, Social Security Administration, 6401 Security Boulevard, Baltimore, Maryland 21235–6401, (410) 965–1020. For information on eligibility or filing for benefits, call our national toll-free number, 1–800–772–1213 or TTY 1–800–325–0778, or visit our Internet site, Social Security Online, at *http://www.socialsecurity.gov.*

SUPPLEMENTARY INFORMATION:

Background

We are making final the rules for evaluating visual disorders we proposed in a notice of proposed rulemaking (NPRM) published in the **Federal Register** on February 13, 2012 (77 FR 7549). The preamble to the NPRM provides a full explanation of the background of these revisions. You can view the preamble by visiting www.regulations.gov and searching for document ''SSA–2010–0078–0001.'' We are making a number of changes because of public comments to the NPRM. We explain those changes in our summary of the public comments and our responses later in this preamble. We are also making a number of minor editorial changes throughout these final rules.

Why are we revising the listings for evaluating visual disorders?

We are revising the listings for evaluating visual disorders to update the medical criteria, clarify how we evaluate visual disorders, and address adjudicator questions.

When will we begin to use these final rules?

We will begin to use these final rules on their effective date. We will continue to use the current rules until the date these final rules become effective. We will apply the final rules to new applications filed on or after the effective date of these final rules and to claims that are pending on or after the effective date.[1] These final rules will remain in effect for 5 years after the date they become effective, unless we extend them, or revise and issue them again.

Public Comments

In the NPRM, we provided the public with a 60-day comment period, which ended on April 13, 2012. We received 12 public comment letters. The comments came from members of the public, national medical organizations, disability examiners, and a national association representing disability examiners in the State agencies that make disability determinations for us. We have summarized the comments below because some of them were long. We summarized only those comments with concerns or suggestions and responded to the significant issues that were relevant to this rulemaking. Some commenters supported the proposed changes and noted the provisions with which they agreed. While we appreciate those comments, we have not summarized or responded to them

[1] This means that we will use these final rules on and after their effective date in any case in which we make a determination or decision. We expect that Federal courts will review our final decisions using the rules that were in effect at the time we issued the decisions. If a court reverses the Commissioner's final decision and remands a case for further administrative proceedings after the effective date of these final rules, we will apply these final rules to the entire period at issue in the decision we make after the court's remand.