# Consideration of Comments on 4th Draft of FAC-003-2 Transmission Vegetation Management —Project 2007-07 Vegetation Management

The Vegetation Management Standard Drafting Team thanks all commenters who submitted comments on the 4th draft of reliability standard FAC-003-2 — Transmission Vegetation Management. This standard and its associated implementation plan and technical reference paper were posted for a 30-day public comment period from June 17, 2010 through July 17, 2010. The stakeholders were asked to provide feedback on the standard through a special Electronic Comment Form. There were 45 sets of comments, including comments from more than 100 different people from over 50 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

The standard and its associated implementation plan and technical reference paper were balloted from July 9 – 19, 2010. The voting had a quorum of 86.18 percent and an affirmative vote of 65.93 percent. Because at least one negative ballot included a comment and the affirmative votes did not meet the two thirds threshold for approval, the results were not final.

On November 4, 2010, NERC staff provided a Quality Review of FAC-003-2 to the Standards Committee (SC). The SC met on November 11, 2010 to determine if the draft standard should proceed to posting. During the meeting, the SC requested the Vegetation Management Standard Development Team (VMSDT) to work with NERC staff in addressing the items identified in the Quality Review. The VMSDT conducted several conference calls and acted in good faith to produce Draft 5 of FAC-003-2. The VMSDT considered the feedback provided in the Quality Review by NERC staff and reached consensus in the following areas:

1. Elaborated upon the Purpose Statement to encompass more of the standard's content.
2. Added a Rationale text box to the section 4 - Applicability to explain the exclusion of substation facilities. Clarified 4.2.4 by adding specific boundary details.
3. Updated Requirement R1 and R2 to emphasize the "planning" time horizon as the applicable temporal context.
4. Elaborated upon the explanation in the Rationale text boxes for R1 and R2 to highlight the range of non-compliant performance.
5. Re-organized the content of Requirement R3 for improved readability.
6. Augmented Requirement R5 to include a "reliability objective".
7. Modified Requirement R6 and the associated VSLs for improved enforceability and for consistency in the units of measure between the Requirement and the associated VSLs.
8. Modified Requirement R7 and the associated VSLs for improved enforceability and for consistency in the units of measure between the Requirement and the associated VSLs.
9. Updated the Evidence Retention section in accordance with current guidelines.

Modifications incorporated into Draft 5 of FAC-003-2 in response to stakeholder comments include:

A. Removed reference to Active Transmission Line Right of Way (ROW).
B. Redefined the Glossary term for ROW to address Paragraph 734 of FERC Order 693 addressing the width of ROW to be maintained.
C. Redefined the Glossary term for Vegetation Inspection to include identifying hazards to the line inside the ROW.
D. Included the term referred to as "applicable lines" under Section 4.2 Facilities.

E. Removed Section4.4 and footnote 2 addressing “force majeure” and addressed the issue in new footnotes 2, 3 and 4.
F. In R1./R2 – M1/M2
   - Added reference “into the MVCD” (Minimum Vegetation Clearing Distance – MVCD) into the text.
   - Eliminated “types of encroachment” and added “The four types of failure to manage vegetation, in order of increasing severity.”
   - In M1/M2, added a paragraph defining “later confirmation of a Fault by the TO as a real-time observation.”
   - Added to the Rationale box types of failures to manage vegetation.
G. In R4, changed “qualified personnel” to TO.
H. In R5, added the term “is constrained from performing vegetation work” and referenced MVCD. Also removed reference to the 2003 northeast blackout from Rationale box
I. In R6, added the phrase “ but no more than 18 months between inspections.” Also added Footnote 3.
J. In R7, replaced major storms bullet with “circumstances that are beyond the control of a Transmission Owner.” Also added Footnote 4 to this requirement.
K. In Additional Compliance Information
   - Category 2 was split into two parts recognizing Interconnection Reliability Operating Limits (IROL’s) and Major Western Electric Coordinating Council (WECC) Transfer Paths.
   - Added Category 3 for Fall-ins from outside the ROW.
   - Category 4 was split into two parts recognizing IROL’s and Major WECC Transfer Paths
L. Removed alternate versions of Violation Severity Levels (VSL’s) for Requirements R1 and R2.
M. Deleted Table 3 from the Guidelines and Technical Basis section.

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

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

## Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

| | | Commenter | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Group | Guy Zito | Northeast Power Coordinating Council | | | | | | | | | | X |

| | Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|---|
| 1. | Alan Adamson | New York State Reliability Council, LLC | NPCC | 10 |
| 2. | Gregory Campoli | New York Independent System Operator | NPCC | 2 |
| 3. | Kurtis Chong | Independent Electricity System Operator | NPCC | 2 |
| 4. | Sylvain Clermont | Hydro-Quebec TransEnergie | NPCC | 1 |
| 5. | Michael Schiavone | National Grid | NPCC | 1 |
| 6. | Gerry Dunbar | Northeast Power Coordinating Council | NPCC | 10 |
| 7. | Dean Ellis | Dynegy | NPCC | 5 |
| 8. | Ben Eng | New York Power Authority | NPCC | 4 |
| 9. | Brian Evans-Mongeon | Utility Services | NPCC | 8 |
| 10. | Peter Yost | Consolidated Edison Co. of New York, Inc. | NPCC | 3 |
| 11. | Brian L. Gooder | Ontario Power Generation Incorporated | NPCC | 5 |
| 12. | Kathleen Goodman | ISO - New England | NPCC | 2 |
| 13. | Chantel Haswell | FPL Group, Inc. | NPCC | 5 |
| 14. | David Kiguel | Hydro One Networks Inc. | NPCC | 1 |
| 15. | Michael R. Lombardi | Northeast Utilities | NPCC | 1 |

| | | Commenter | Organization | Industry Segment | | | | | | | | | |
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| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 16. | | Randy MacDonald | New Brunswick System Operator | NPCC | | | | | 2 | | | | |
| 17. | | Bruce Metruck | New York Power Authority | NPCC | | | | | 6 | | | | |
| 18. | | Lee Pedowicz | Northeast Power Coordinating Council | NPCC | | | | | 10 | | | | |
| 19. | | Robert Pellegrini | The United Illuminating Company | NPCC | | | | | 1 | | | | |
| 2. | Group | Denise Koehn | Bonneville Power Administration | X | | X | | X | X | | | | |
| | | **Additional Member** | **Additional Organization** | **Region** | | | | | **Segment Selection** | | | | |
| 1. | | Chuck Sheppard | BPA, Tx Vegetation/Access Road Mgmt | WECC | | | | | 1 | | | | |
| 2. | | Steve Narolski | BPA, Tx Vegetation/Access Road Mgmt | WECC | | | | | 1 | | | | |
| 3. | | Vince Ierulli | BPA, Transmission Line Design | WECC | | | | | 1 | | | | |
| 4. | | Frank Weintraub | BPA, Transmission Line Design | WECC | | | | | 1 | | | | |
| 5. | | Daniel Tuominen | BPA, Transmission Line Design | WECC | | | | | 1 | | | | |
| 6. | | Joel Billings | BPA, Transmission Line Design | WECC | | | | | 1 | | | | |
| 7. | | Michael Staats | BPA, Transmission Engineering | WECC | | | | | 1 | | | | |
| 8. | | Don Swanson | BPA, Transmission Line Maintenance Technical Svcs | WECC | | | | | 1 | | | | |
| 3. | Group | Sasa Maljukan | Hydro One | X | | | | | | | | | |
| | | **Additional Member** | **Additional Organization** | **Region** | | | | | **Segment Selection** | | | | |
| 1. | | David kiguel | Hydro One Networks Inc. | NPCC | | | | | 1 | | | | |
| 2. | | Patrick HOWE | Hydro One Networks Inc. | NPCC | | | | | 1 | | | | |
| 3. | | Leslie KOCH | Hydro One Networks Inc. | NPCC | | | | | 1 | | | | |
| 4. | | Jonathan MARRIOTT | Hydro One Networks Inc. | NPCC | | | | | 1 | | | | |
| 4. | Group | Richard Kafka | Pepco Holdings, Inc - Affiliates | X | | X | | X | X | | | | |
| | | **Additional Member** | **Additional Organization** | **Region** | | | | | **Segment Selection** | | | | |
| 1. | | Pat Byrne | Potomac Electric Power Company | RFC | | | | | 1 | | | | |
| 2. | | Dave Paduda | Potomac Electric Power Company | RFC | | | | | 1 | | | | |
| 3. | | Steve Benn | Delmarva Power & Light | RFC | | | | | 1 | | | | |
| 4. | | Olivia Watts | Atlantic City Electric | RFC | | | | | 1 | | | | |
| 5. | Group | Joseph DePoorter | MRO's NERC Standards Review Subcommittee (nsrs) | | | | | | | | | | X |

| | | Commenter | Organization | Industry Segment | | | | | | | | | |
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| | | **Additional Member** | **Additional Organization** | **Region** | | | | | **Segment Selection** | | | | |
| | 1. | Mahmood Safi | OPPD | MRO | | | | | 1, 3, 5, 6 | | | | |
| | 2. | Chuck Lawrence | ATC | MRO | | | | | 1 | | | | |
| | 3. | Tom Webb | WPSC | MRO | | | | | 3, 4, 5, 6 | | | | |
| | 4. | Jason Marshall | MISO | MRO | | | | | 2 | | | | |
| | 5. | Jodi Jenson | WAPA | MRO | | | | | 1, 6 | | | | |
| | 6. | Ken Goldsmith | ALTW | MRO | | | | | 4 | | | | |
| | 7. | Dave Rudolph | BEPC | MRO | | | | | 1, 3, 5, 6 | | | | |
| | 8. | Eric Ruskamp | LES | MRO | | | | | 1, 3, 5, 6 | | | | |
| | 9. | Joseph Knight | GRE | MRO | | | | | 1, 5, 6 | | | | |
| | 10. | Joe DePoorter | MGE | MRO | | | | | 3, 4, 5, 6 | | | | |
| | 11. | Scott Nickels | RPU | MRO | | | | | 4 | | | | |
| | 12. | Terry Harbour | MEC | MRO | | | | | 1, 3, 5, 6 | | | | |
| | 13. | Carol Gerou | MRO | MRO | | | | | 10 | | | | |
| 6. | Group | Sam Ciccone | FirstEnergy | | | X | X | X | X | | | | |
| | | **Additional Member** | **Additional Organization** | **Region** | | | | | **Segment Selection** | | | | |
| | 1. | Rebecca Spach | FE | RFC | | | | | 1 | | | | |
| | 2. | Katrina Schnobrich | FE | RFC | | | | | 1 | | | | |
| | 3. | Doug Hohlbaugh | FE | RFC | | | | | 1, 3, 4, 5, 6 | | | | |
| | 4. | Dave Folk | FE | RFC | | | | | 1, 3, 4, 5, 6 | | | | |
| 7. | Group | Michael Gammon | Kansas City Power & Light | X | | X | | X | X | | | | |
| | | **Additional Member** | **Additional Organization** | **Region** | | | | | **Segment Selection** | | | | |
| | 1. | Jennifer Flandermeyer | KCPL | SPP | | | | | 1, 3, 5, 6 | | | | |
| | 2. | Duane Ansteate | KCPL | SPP | | | | | 1, 3, 5, 6 | | | | |
| | 3. | Dean Beasley | KCPL | SPP | | | | | 1, 3, 5, 6 | | | | |
| 8. | Group | Mallory Huggins | NERC Staff | | | | | | | | | | |
| | | **Additional Member** | **Additional Organization** | **Region** | | | | | **Segment Selection** | | | | |
| | 1. | Robert Novembri | NERC | NA - Not Applicable | | | | | NA | | | | |

| | | Commenter | Organization | Industry Segment | | | | | | | | | |
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| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 2. | Gerry Adamski | | NERC | NA - Not Applicable | | | | | NA | | | | |
| 3. | Joel deJesus | | NERC | NA - Not Applicable | | | | | NA | | | | |
| 4. | Valerie Agnew | | NERC | NA - Not Applicable | | | | | NA | | | | |
| 5. | Mike DeLaura | | NERC | NA - Not Applicable | | | | | NA | | | | |
| 6. | Maureen Long | | NERC | NA - Not Applicable | | | | | NA | | | | |
| 7. | David Taylor | | NERC | NA - Not Applicable | | | | | NA | | | | |
| 8. | Herb Schrayshuen | | NERC | NA - Not Applicable | | | | | NA | | | | |
| 9. | Group | Louis Slade | Dominion | X | | X | | X | X | | | | |
| | **Additional Member** | | **Additional Organization** | **Region** | | | | | **Segment Selection** | | | | |
| 1. | Aaron Jonas | | | SERC | | | | | 1 | | | | |
| 2. | John Loftis | | | SERC | | | | | 3 | | | | |
| 3. | Mike Garton | | | | | | | | 5 | | | | |
| 10. | Individual | Brandy A. Dunn | Western Area Power Administration | X | | | | | | | | | |
| 11. | Individual | Jana Van Ness | Arizona Public Service Company | X | | X | | X | X | | | | |
| 12. | Individual | Steve Rueckert | Western Electricity Coordinating Council | | | | | | | | | | X |
| 13. | Individual | Luke Diruzza | Tampa Electric Company | X | | X | | X | X | | | | |
| 14. | Individual | Silvia Parada Mitchell | FPL FPL Corporate Compliance | X | | | | X | X | | | | |
| 15. | Individual | JT Wood | Southern Company Transmission | X | | X | | | | | | | |
| 16. | Individual | Linwood Blacksmith | Tri-State Generation & Transmission | X | | | | | | | | | |
| 17. | Individual | David Burke | Orange and Rockland Utilities, Inc. | X | | X | | | | | | | |
| 18. | Individual | Weston Davis | Central Maine Power Company, Iberdrola USA | X | | | | | | | | | |
| 19. | Individual | Kasia Mihalchuk | Manitoba Hydro | X | | X | | X | X | | | | |
| 20. | Individual | Jonathan Appelbaum | The United Illuminating Company | X | | | | | | | | | |
| 21. | Individual | Patrick Simons | Idaho Power Company | X | | | | | | | | | |
| 22. | Individual | Sam Stonerock | Southern California Edison Company | X | | | | X | X | | | | |

| | | Commenter | Organization | Industry Segment | | | | | | | | | |
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| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 23. | Individual | Marty Berland | Progress Energy | X | | X | | X | X | | | | |
| 24. | Individual | John Bee | Exelon | X | | X | | X | | | | | |
| 25. | Individual | Hugh Conley | Allegheny Power | X | | | | | | | | | |
| 26. | Individual | Edward Davis | Entergy Services | X | | X | | X | X | | | | |
| 27. | Individual | Jon Kapitz | Xcel Energy | X | | X | | X | X | | | | |
| 28. | Individual | Gordon Rawlings | BC Hydro | X | X | X | | X | | | | | |
| 29. | Individual | Bill Rees | BGE Forestry Management | X | | | | | | | | | |
| 30. | Individual | Michael R. Lombardi | Northeast Utilities | X | | X | | X | | | | | |
| 31. | Individual | Bryan Taylor | Idaho Power | X | | | | | | | | | |
| 32. | Individual | Anne Beard | PNM | X | | X | | | | | | | |
| 33. | Individual | James Sharpe | South Carolina and Gas | X | | X | | X | X | | | | |
| 34. | Individual | Greg Rowland | Duke Energy | X | | X | | X | X | | | | |
| 35. | Individual | Andrew Z.Pusztai | American Transmission Company | X | | | | | | | | | |
| 36. | Individual | Terry Harbour | MidAmerican Energy | X | | | | | | | | | |
| 37. | Individual | Claudiu Cadar | GDS Associates | X | | | | | | | | | |
| 38. | Individual | Joe Knight | Great River Energy | X | | X | | X | X | | | | |
| 39. | Individual | Kirit Shah | Ameren | X | | X | | X | X | | | | |
| 40. | Individual | Earl V. Burnside | PPL Electric Utilities | X | | X | | | | | | | |
| 41. | Individual | Jianmei Chai | Consumers Energy Company | | | X | X | X | | | | | |
| 42. | Individual | Michael Pakeltis | CenterPoint Energy | X | | | | | | | | | |
| 43. | Individual | E Hahn | MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA) | X | | | | | | | | | |
| 44. | Individual | George Czerniewski | Consolidated Edison Company of New York Inc | X | | | | | | | | | |

| | | Commenter | Organization | Industry Segment | | | | | | | | | |
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| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 45. | Individual | James W. Smith | ITC Transmission | | | | | | | | | | |

1. **The SDT replaced the defined term "Active Transmission Line Right of Way" with footnote number 2 that provides a description of "active transmission line ROW" and added Table 3, "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW" to support that description. Do you agree? Please explain.**

**Summary Consideration:**

**Of 45 respondents, there is 1 abstention, 19 are in agreement, and 25 are in disagreement.**

**The major comment issues raised are:**

1. **The values used in Table 3 needs to be justified.**
2. **The definition of an active transmission line ROW ought to be a Glossary term.**
3. **The Table does not account for different structure designs and the term "centerline" is not applicable in all cases.**

**The VM SDT considerations for the major comment issues are:**

1. **The VM SDT added explanatory text in the Guideline and Technical Basis section.**
2. **Based on comments from 4th posting the SDT is revising the definition of ROW in the NERC Glossary.**
3. **Table 3 has been removed.**

**Some minor comment issues are:**

1. **Add distances for DC lines into Table 3.**
2. **The term and Table 3 needs further clarification.**

**The VM SDT considerations for the minor comment issues are:**

1. **Table 3 has been removed.**
2. **Table 3 has been removed.**

| | Organization | Yes or No | Question 1 Comment |
|---|---|---|---|
| 1 | MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA) | | |
| 2 | Hydro One | No | A DC table for Table 3 similar to the MVCD table should be added.There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table. The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. The description does not take into account vertical versus horizontal design configuration. Consideration should be given for the type of construction as different construction types (H-Frame, Lat-tice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations. |

| | Organization | Yes or No | Question 1 Comment |
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| | | | Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. There is published literature using the term “cleared width” to indicate the distance from the outer phase to the tree line. This distance should be used in the Active ROW definition. The word easement is also used in the definition. Is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include “danger tree rights” on land? These questions need to be addressed in the standard (in text) and technical reference document (in graphics). |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 3 | Allegheny Power | No | Allegheny Power strongly disagrees with the numbers or widths stated within Table 3. These numbers seem arbitrary and have no accompanying reasonable explanation as to their origin, basis, or other criteria noting the rationale for inclusion in this standard. This inclusion effectively prohibits a TO from establishing corridor widths less than the widths (which may be easily possible by utilizing various tower or structures heights or configurations) stated in Table 3 without placing the TO in extreme jeopardy of non-compliance issues from a falling off-corridor tree, during minor storm conditions as an example. Furthermore, this Table insinuates the TO has no ability to successfully manage vegetation WITH NO RESULTING OUTAGES or encroachments within the MVCD from off-corridor trees where corridors are less that the widths stated in Table 3.Allegheny Power suggests that the definition of the “Active Transmission line Right Of Way” be “the transmission line ROW corridor that is actively maintained as part of the entity's vegetation management plan.". |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 4 | FPL Corporate Compliance | No | Although there is support for making Active Transmission Line Right of Way a clearly defined term, and the foundation for compliance with FAC-003-2, the distances in the table are arbitrary and are not supported by any scientific |

| | Organization | Yes or No | Question 1 Comment |
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| | | | or engineering analysis. It is possible that such a table could be interpreted to define the minimum width of future lines. Different construction configurations require different ROW widths. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 5 | PPL Electric Utilities | No | Centerline (CL) distances shown in Table 3 are shown as Minimal distances from CL. If utility is not able to define its ultimate ROW, due to CL agreement or other circumstances, these minimal distances may not be applicable and as such could result in non-compliance as written. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 6 | Southern Company Transmission | No | Depending on the intent this may create a problem. We are concerned the addition of Table 3 could be interpreted to mean something completely different than what we believe to be its intention. Please consider alternate wording to Footnote 2: A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the active transmission line ROW cleared width it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.If the SDT determines keeping Table 3 is the appropriate course of action, we recommend clarifying its intent better; either in a footnote or in the title. Adding a footnote stating the Table is not applicable if the distance from the center line of the conductor to the right-of-way edge is less than the appropriate distance indicated in the table.Another option might be to add a statement to the title such as, “If the distance from the centerline of the circuit to the edge of the easement is less than the values in Table 3, that distance is considered active ROW”. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way.** | | |

| | Organization | Yes or No | Question 1 Comment |
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| | **Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 7 | Ameren | No | Does this mean wider ROW easements will need to be acquired to be compliant or will this apply to ROW's for new circuits going forward? |
| | **Response: Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 8 | Progress Energy | No | In Applicability Section 4.4, "active transmission line ROW" is not capitalized indicating it is not a defined term, but Footnote 2 is effectively a definition for active transmission line ROW. However, in the first paragraph of Section 5 Background, Active Transmission Line Right-of-Way is capitalized indicating it's a defined term. It would seem cleaner to make "Active Transmission Line Right of Way" a formal NERC definition. Alternatively and at a minimum, Footnote 2 should be revised to say "An active transmission line ROW is a strip or corridor..." and also in Section 5 Background, "Active Transmission Line Right of Way" should be changed to no longer be capitalized. |
| | **Response: Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 9 | PNM | No | ROW easements vary according to land ownership therefore, potentially subjecting the utility to be liable for land outside of easement/ROW. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 10 | Central Maine Power Company, Iberdrola USA | No | Table 3 distances may not be appropriate, for example table 3 should reflect a clearance zone based on construction type, topography, species, or growth rates. Table 3 could give the impression that the listed distances are the maximum, therefore suggest table 3 be removed or revised.The Active Transmisson Line Right-of-Way defination uses the word easement, which most likely would include danger trees in situations where danger removals |

| | Organization | Yes or No | Question 1 Comment |
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| | | | are included in the the easement language. This would expand the scope of FAC 003 2 beyond the cleared right-of-way width. |
| | **Response: The SDT agrees that Table 3 does not reflect the structural differences which directly determines the right of way width. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 11 | Consumers Energy Company | No | Table 3 does not adequately address ROW width requirements based on the type of construction used for structures, especially for the two lower voltage classes, 69-138kV and 139-230 kV. Lines constructed on H-Frame structures have a much wider footprint across the ROW than do single pole construction and most steel tower construction types. The minimum ROW width listed in Table 3 for a 138 kV line constructed on a wooden H-Frame may put the outside conductor within MVCD under windy conditions due to wind displacement of conductors and trees.Consumers Energy recommends that Table 3 be modified to describe the minimum distance in the table is the vertical plane of the outside conductor to the edge of the active transmission ROW and therefore independent of the width of the structure construction type. |
| | **Response: The SDT agrees that Table 3 does not reflect the structural differences which directly determines the right of way width. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 12 | The United Illuminating Company | No | The definition has been altered. The last sentence "However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes..." was added. The concept of the easement is confusing and not included in the Supplemental Reference. Table 3 of the standard is titled "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW", no mention of easements. It is suggested that the definition state "strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. At a minimum the width is to be the distances as shown in Table 3 for various voltage classes."The |

| | Organization | Yes or No | Question 1 Comment |
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| | | | proper location for the definition is in the Glossary. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 13 | Dominion | No | The distances proposed in Table 3 - Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW may not be consistent with the centerline distances cleared and maintained by the TO. For example, a TO maintaining 75' from centerline for a 500kV circuit would be required to clear and maintain an additional 12.5' to meet the proposed standard's requirement. We suggest either allowing individual TOs to maintain active ROW widths consistent with their normal clearing/maintenance practices, going back to Draft 3's definition of Active Transmission Line Right-of-Way, or changing the footnote in Draft 4 to read:A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the portion of the ROW that has been cleared must at least meet design clearance requirements such as National Electric Safety Code or other design criteria, for the reliable operation of active facilities. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 14 | BC Hydro | No | The footnote definition is ok but Table 3 is poorly developed. The voltage classes should be better segregated (e.g. nominal voltage 69kV, 138kV, 230kV, 287kV, 345kV, 500kV, 765kV) along with distances in feet and metres as Canadian utilities are metric. Also the table should include recommended right of way widths for single circuits. The assumption made in the footnote is that the legal easement is larger than in Table 3. However, as currently defined, some of the distances in Table 3 exceed statutory rights of way at our utility and exceed engineering standards as defined by the Canadian Standards Association - Overhead Systems (CAN/CSA C22.3 No. 1-6). Also, clearances will very much depend on line design (e.g. structure architecture such as flat, Post T, H-frame, steel lattice, and other variables |

| | Organization | Yes or No | Question 1 Comment |
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| | | | such as ruling span length, conductor type used, etc.) To some degree this will vary quite a bit between utilities. As such Table 3 as currently presented is not workable. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 15 | Exelon | No | The term "Centerline of the Circuit" in Table 3 is not defined. Until it is defined, there is no way to know if the standard is technically reasonable or whether existing circuits would be in violation of the standard and unable to operate. In addition, it is unclear what types of construction and span lengths were used to develop the distances for active right-of-way widths in Table 3. Furthermore, it is not clear whether Table 3 contains requirements against which compliance will be measured or best practice guidelines. Footnote 2, in the background section, compounds this ambiguity. In short, the lack of a definition for "Centerline" combined with Footnote 2 and Table 3 make this draft unclear and unenforceable. Exelon does not necessarily have easement widths for all transmission lines that equal those defined in Table 3 of this draft; This may require the acquisition of additional easements, if even possible. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 16 | Northeast Utilities | No | The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. Consideration should be given for the type of construction as different construction types (H-Frame, Lattice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from |

| | Organization | Yes or No | Question 1 Comment |
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| | | | conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations.Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 17 | Idaho Power Company | No | The way I interpret this, the new definition of active transmission line right of way takes away our ability to clear potential fall ins if they are outside of the active transmission line ROW> |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 18 | CenterPoint Energy | No | There is no rationale provided for the “minimum distances” stated in Table 3, and they far exceed the ROW widths that CenterPoint Energy owns (typical total 100’ ROW width for 2-ckt 345kV line) for its current 345kV system, and as such, are open for misapplication and misinterpretation as an intended minimum standard for making a fall-in determination for R1 and R2 outside the legal limits of the utility. Table 3 should be deleted. If kept, there should be sufficient rationale included within the Guidelines and Technical Basis to explain how it was derived and how it is to be used within the Standard. CenterPoint Energy agrees with the removal of “active transmission line ROW” as a defined term; however, the footnote should be deleted as well since it attempts to create a definition which is not accurate, necessary or |

| | Organization | Yes or No | Question 1 Comment |
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| | | | useful. Throughout the Standard, the phrase "active transmission line ROW" should be replaced with "transmission line ROW" to eliminate the qualifying term "active". In making a fall-in determination for R1 and R2, the limit should be "within the full extent of the Transmission Owner's transmission ROW as defined by easement, fee simple, or other legal rights" as discussed in the Guidelines and Technical Basis regarding the vegetation management maintenance approach. This places the determination of the width of the ROW for determination of fall-in violations clearly on the Transmission Owner and the within the limits of its legal rights to control the vegetation that has fallen into the line under R1 and R2. |
| | **Response: The SDT thanks you for your comments. The SDT disagrees with the point that the TO should be required to clear the entire extent of legal rights. FERC Order 693 agreed that expansion easements needed to be adressed. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 19 | Northeast Power Coordinating Council | No | There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table.The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. The description does not take into account vertical versus horizontal design configuration. Consideration should be given for the type of construction as different construction types (H-Frame, Lattice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the |

| | Organization | Yes or No | Question 1 Comment |
|---|---|---|---|
| | | | distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations.Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. There is published literature using the term “cleared width” to indicate the distance from the outer phase to the tree line. This distance should be used in the Active ROW definition. The word easement is also used in the definition. Is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include “danger tree rights” on land? These questions need to be addressed in the standard (in text) and technical reference document (in graphics). |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 20 | Arizona Public Service Company | No | These clearances could exceed the permitted ROW’s on federal lands and the utility has no legal right to clear beyond those rights. In some cases the permitted ROW can exceed those distance and federal agencies could not allow you to clear beyond those clearances in this version. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 21 | Entergy Services | No | This is very unclear, and creates much uncertainty as to how certain potential outage situations should be reported. Clarification language should be added within the Standard to help define and guide the TO's actions when an outage occurs from a location at a point that is less than the documented ROW boundaries (Easements) but greater than the ROW distances represented in Table 3. It is unclear which distance should guide our |

| | Organization | Yes or No | Question 1 Comment |
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| | | | reporting actions........ROW Document Width, Table 3 ROW Widths, or the lesser of the two.......See scenarios / examples below for consideration to aid with clarification points:Example 1: If our documented ROW width for a 500kV line is 100' from centerline (200' total ROW width) and we have a fall in from 90' from centerline, do we report this as a Category 2 Outage due to the fact that it fell from within our ROW limits, or is it non-reportable due to the fact that it is located at a greater distance than 87.5' from the centerline of the ROW as listed in Table 3 in the Standard?Example 2: How does maintenance and outage reporting correlate with the example defined as follows.......You have a 230 kV line situated on one side of a 150' wide ROW that was initially cleared to a width that would accommodate 2 separate parallel transmission lines and structures. The second set of lines/structures have not yet been constructed, and the current Transmission line is situated on one side of the 150' ROW, and is being maintained to the edge of the actual ROW on the side of the ROW that it was constructed on (maintained to a distance of 50' from centerline that puts it at the legal edge of the ROW), but it has been typically maintained to a distance of approximately 60' from centerline to the inside portion/other side of the ROW (the side of the ROW that has never been cleared), but a tree falls into the line from approx 58' from centerline (2' within the 60' distance typically being maintained on that line).......would this be considered a Category 2 outage since it was approx 2' within the average width being maintained on that side of the ROW or would it not be reported due to the fact that it was located at a distance greater than 50' as indicated in Table 3?? |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 22 | Kansas City Power & Light | No | This needs to be a defined term since the Standard uses that as a basis for use with Table 3. Using this term as a footnote does not allow the industry to weigh in on its definition. Footnotes should not be used as a means of definition or clarification. Footnotes are for references to other sources of statements or documents that support a particular thought. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way.** | | |

| | Organization | Yes or No | Question 1 Comment |
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| | **Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 23 | Xcel Energy | No | We believe Active Transmission ROW should be a defined term, not buried in a "footnote" of the "Other" section of a Standard. It still begs the question - what is an "active transmission facility"? Regarding the substance, overall we believe that the Active Transmission ROW should not include the new reference to Table 3. This newly added sentence in footnote 2, referencing Table 3, is confusing to interpret. If retained, please rephrase to make it clearer that a Transmission Owner never has to increase the size of its easement/land right to satisfy this table. As drafted, our team had various interpretations and it is unclear whether the intent is that a Transmission Owner has to increase its easement or acquire land to meet this requirement, or conversely if the easement is well beyond the values in Table 3, the Transmission Owner has to maintain that the entire easement or only the values in Table 3."Active Transmission Right of Way" is still used in the first paragraph of the Background section.In total, we suggest that the definition of Activate Transmission ROW return to the version used in the prior draft and be placed in the definition section. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 24 | ITC Transmission | No | We disagree with footnote comment as this adds confusion to the standard. Is a footnote considered part of the standard or not? The reference to table #3 is something new and has never been discussed or commented on prior to this revision and appears to be a bright line concept which we are in total disagree with. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 25 | FirstEnergy | No | We do not support replacement of the term Active Transmission Line Right of Way with Footnote #2. Since the term "active transmission line ROW" is used in the requirements, compliance section, and VSLs, and since the drafting team has a very definite view of what this term means, the term should be a |

| | Organization | Yes or No | Question 1 Comment |
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| | | | definition included in the NERC Glossary. Also, since ROW is defined in the NERC Glossary, it further supports the reasons this term should also be defined. Therefore, we suggest the team revert back to the Draft 3 proposed NERC Glossary term.Lastly, we do not support the addition of Table 3. We believe this adds unnecessary prescriptiveness to the requirements. It is also not clear if this Table was intended to be mandatory because the only reference in the table is in Footnote #2. If the SDT feels this table is a useful tool that should be included in the standard, then we suggest adding it to the Guidelines section as optional information. Also, reference to this Table 3 in the Active Transmission Line ROW definition should be removed. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 26 | Tampa Electric Company | No | We have concern with the “Minimum Distances” as listed in Table 3. What analytical methodology, criteria and rationale was utilized to determine each recommended distance? In addition, we have concerns regarding the change to a pre-determined distance. This seems to be a major shift from the vegetation to conductor methodology employed previously and throughout this standard? NERC/FERC must recognize that while protecting and securing grid reliability, each utility must also balance the environmental, political, customer and economic issues and impacts which will occur with the implementation of the Table 3 clearances. We question whether this is the most responsible action to take given the current state of the economy as well as the environmental and political sensitivity impacts which will result. Tampa Electric questions whether Table 3 will improve System reliability. Since the inception of standard FAC-003-1 Tampa Electric has not had a Category 1 or Category 2 outage on our 230kV Transmission System. We don’t believe that the changes proposed to table 3 will improve overall service reliability. It is Tampa Electric’s opinion that each utility should define the width of its own Active Transmission line ROW. However, if such a table is to be utilized, Tampa Electric recommends the following changes or adjustments to Table 3.1. Expand the table to account for the various types of Transmission construction; i.e. vertical versus horizontal conductor configurations.2. Use a distance from the outermost conductor, not the centerline. This will account for construction type and better achieve a |

| | Organization | Yes or No | Question 1 Comment |
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| | | | consistent clearance from conductors.3. We recommend reducing the distances in Table 3 by 12.5 feet for each voltage category. 4. Specify whether the voltage is based upon the design or operating voltage.5. Reformat the voltage ranges to 100kV - 200kV, 200kV - 300kV, 300kV - 400kV, etc. as an example; this would create a more appropriate range of voltages and clearance distances. The reformatted voltage ranges eliminate confusion. For example, under the current proposal it is unclear in which category a nominal 230kV line should be since sometimes such a line can operate at up to 232kV during low-load conditions. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 27 | American Transmission Company | Yes | |
| 28 | BGE Forestry Management | Yes | |
| 29 | Great River Energy | Yes | |
| 30 | MidAmerican Energy | Yes | |
| 31 | NERC Staff | Yes | |
| 32 | Pepco Holdings, Inc - Affiliates | Yes | |
| 33 | South Carolina and Gas | Yes | |
| 34 | Western Electricity Coordinating Council | Yes | |

| | Organization | Yes or No | Question 1 Comment |
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| 35 | GDS Associates | Yes | - ROW abbreviation comes prior to the full term (marked footnote prior to the full term as stated in 5. Background). Please make correction accordingly. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 36 | Duke Energy | Yes | However, due to different design attributes of transmission lines, it may be better to change the distance in Table 3 from a centerline distance to a “Minimum Full Active Transmission Line ROW Width Distance”. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 37 | Idaho Power | Yes | I support the description for the active right of way.  However, I believe there needs to be a provision that addresses identifying potential hazards outside the active right of ways that may pose a risk to the transmission lines. |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 38 | Manitoba Hydro | Yes | Please add metric equivalents in the standard.While it makes some aspects easier around pointing to what we need to keep "clear" to meet NERC rules - it does limit some of our flexibility to design lines and ROWs to your own standards.  Also, the minimum only applies when you have easement larger than the minimums in table 3, and I would assume that does not relieve you of the responsibility to maintain ROWs appropriately if the design of your lines requires a wider ROW. |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |

| | Organization | Yes or No | Question 1 Comment |
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| 39 | Southern California Edison Company | Yes | SCE appreciates the SDT's efforts to replace the defined term with a set of minimum distances. However, the proposed new Table 3 appears to assume a horizontal configuration of transmission lines. Thus, it would appear that those lines configured vertically (for example, two circuits on opposite sides of a tower), the "active right of way" required would be at least twice as large as that for horizontal lines. SCE respectfully recommends a footnote be added to Table 3 that allows the TO to recalculate the active right of way for lines in a vertical configuration, based on a horizontal line configuration. |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 40 | Western Area Power Administration | Yes | Suggest using a total right-of-way width in Table 3 rather than a distance measured from centerline. |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 41 | Tri-State Generation & Transmission | Yes | Table 3 should be referenced as a guideline only. |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 42 | MRO's NERC Standards Review Subcommittee (nsrs) | Yes | The NSRS agrees in whole to the question but has the SDT taken into consideration the difference in ROW may be different in Urban and Rural settings? |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |

| | Organization | Yes or No | Question 1 Comment |
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| 43 | Consolidated Edison Company of New York Inc | Yes | The same verbiage in footnote number 2 should appear below Table 3 to avoid any confusion. |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 44 | Orange and Rockland Utilities, Inc. | Yes | There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table. |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |
| 45 | Bonneville Power Administration | Yes | This distance is reasonable in the table, but due to widely varying designs of structures it does not give a relationship of the outside wire to edge of ROW. It should be noted as outside wire, phase or conductor to edge of ROW.In addition, the effective date should allow transmission owners time to achieve this distance, perhaps one cycle. |
| | **Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** | | |

## 2. In response to comments received regarding the terms "reasonable" and "human errors/human activity", the SDT modified the Other Section and Background Section. Do you agree? Please explain.

**Summary Consideration:**

**Of 45 respondents, there are 3 abstentions, 38 are in agreement, and 4 are in disagreement.**

**The major comment issues raised are:**

1. **Of the 4 in disagreement, only NERC believes "force majeure" statement is not necessary.**
2. **Three respondents believe the "force majeure" statement should be expanded to include Federal, State, Regulatory and legal interference.**

**The VM SDT considerations for the major comment issues are:**

1. **a) The SDT believes this language is appropriate for this standard due to the many factors related to vegetation that are truly outside the TO's control. Unlike the vast majority of other NERC standards, implementation of FAC-003 is not under the absolute control of the utilities. These influences range from landowner and agency obstacles to weather events, and as such the SDT believes the force majeure provisions should be applicable. The recognition of this provision is also supported by 90% of the industry. An attempt at similar language is contained in version 1 but it is ambiguous and lacks clarity. This language adds clarity and reduces the opportunity for mis-application. Further, TO's who elect to invoke "force majeure" must have supporting evidence of such action. The lack of a force majeure section means a Transmission Owner would have a violation of a Requirement, even if the penalty might have been mitigated by the circumstances.**

   **b) However, the SDT moved the force majeure from applicability to a footnote (Footnote 2) based on comments concerning the structure of NERC standards. The footnotes are referenced in R1, R2, and R7. In R6, an exclusion clause was added in Footnote 3.**

3. **The SDT recommends no expansion. The "force majeure" provision is intended to recognize circumstances that are completely outside the TO's control. Federal, State or regulatory interference is certainly a barrier but there are actions available to mitigate such interference. The TO should be aware of such interference and should take whatever corrective actions necessary, up to and including re-rating or de-energizing the line, to avoid a vegetation conflict.**

**Some minor comment issues are:**

1. **One respondent would like to specifically define wind speed.**
2. **Two respondents suggested moving the language elsewhere in the standard.**

**The VM SDT considerations for the minor comment issues are:**

1. **The SDT recommends no change. Wind speed is addressed by “fresh gale”.**
2. **The SDT moved it to a footnote.**

| | Organization | Yes or No | Question 2 Comment |
|---|---|---|---|
| 1 | MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA) | | |
| 2 | Western Electricity Coordinating Council | | |
| 3 | Central Maine Power Company, Iberdrola USA | | No comment suggested. |
| 4 | NERC Staff | No | NERC staff does not support the language in the Other Section. Staff believes that the force majeure provision is unnecessary and calls into question whether NERC and the regions have enforcement discretion to take such things into account in applying other standards that do not include this type of provision. |
| | **Response: The SDT thanks you for your comments. The SDT believes this language is appropriate for this standard due to the many factors related to vegetation that are truly outside the TO’s control. Unlike the vast majority of other NERC standards, implementation of FAC-003 is not under the absolute control of the** | | |

| | Organization | Yes or No | Question 2 Comment |
|---|---|---|---|
| | **utilities. These influences range from landowner and agency obstacles to weather events, and as such the SDT believes the force majeure provisions should be applicable. The recognition of this provision is also supported by 90% of the industry. An attempt at similar language is contained in version 1 but it is ambiguous and lacks clarity. This language adds clarity and reduces the opportunity for mis-application. Further, TO's who elect to invoke "force majeure" must have supporting evidence of such action.** | | |
| 5 | BGE Forestry Management | No | Suggest including in "4.4. Other" a phrase referencing government interference, such as "Federal, State or other regulatory interference, including legal or other legislative actions, that prevents performance to comply with this reliability standard." |
| | **Response: The SDT thanks you for your comments. The "force majeure" provision is intended to recognize circumstances that are completely outside the TO's control. Federal, State or regulatory interferrence is certainly a barrier but there are actions available to mitigate such interference. The TO should be aware of such interference and should take whatever corrective actions necessary, up to and including re-rating or de-energizing the line, to avoid a vegetation conflict.** | | |
| 6 | Kansas City Power & Light | No | The theme of the "Other" section are the conditions for excluding applicable transmission facilities under certain conditions. Recommend the Drafting Team consider renaming this section to "Exclusions". In addition, the term, "Active Transmission Line Right-of-Way" is capitalized in the "Background" section. If it is determined this term should not be a definition, then this should be lower case. |
| | **Response: The SDT thanks you for your comments. The recommendation does not materially change the "force majeure" provision and the SDT does not recommend any change. The SDT did modify the ROW definition in response to industry concerns. Capitalization is now appropriate.** | | |
| 7 | Xcel Energy | No | Xcel Energy urges the retention of the word "reasonable" as a modifier to "control" in Introduction, Section 4.4. The concept that a Transmission Owner should exercise reasonable control is sensible, and is of some aid in countering claims that any incident could be prevented. For example, in Colorado, the transmission of electricity has been judicially found to be subject to the highest degree of care. Without the inclusion of the word "reasonable," Xcel Energy could possibly be faced with a claim that for the exceptions set forth in Introduction, Section 4.4, to apply, the circumstances would have to be "beyond the control (using the highest degree of care) of |

| | Organization | Yes or No | Question 2 Comment |
|---|---|---|---|
| | | | Xcel Energy." Retention of "reasonable" helps counter such claims. Since this section appears to lean toward legal language, the use of the term “reasonable” is better suited for the goal of this section. |
| | **Response: The SDT thanks you for your comments. While we understand the concerns, the word reasonable is ambigous and open to intrepretation and therefore not an appropriate modifier to the language.** | | |
| 8 | Allegheny Power | Yes | |
| 9 | Ameren | Yes | |
| 10 | American Transmission Company | Yes | |
| 11 | Arizona Public Service Company | Yes | |
| 12 | Bonneville Power Administration | Yes | |
| 13 | Consolidated Edison Company of New York Inc | Yes | |
| 14 | Consumers Energy Company | Yes | |
| 15 | FPL Corporate Compliance | Yes | |
| 16 | Dominion | Yes | |
| 17 | Duke Energy | Yes | |

| | Organization | Yes or No | Question 2 Comment |
|---|---|---|---|
| 18 | Entergy Services | Yes | |
| 19 | Exelon | Yes | |
| 20 | GDS Associates | Yes | |
| 21 | Hydro One | Yes | |
| 22 | Idaho Power Company | Yes | |
| 23 | ITC Transmission | Yes | |
| 24 | Manitoba Hydro | Yes | |
| 25 | MidAmerican Energy | Yes | |
| 26 | Northeast Power Coordinating Council | Yes | |
| 27 | Northeast Utilities | Yes | |
| 28 | Orange and Rockland Utilities, Inc. | Yes | |
| 29 | Pepco Holdings, Inc - Affiliates | Yes | |
| 30 | PNM | Yes | |
| 31 | PPL Electric Utilities | Yes | |
| 32 | Progress Energy | Yes | |

| | Organization | Yes or No | Question 2 Comment |
|---|---|---|---|
| 33 | South Carolina and Gas | Yes | |
| 34 | Southern Company Transmission | Yes | |
| 35 | The United Illuminating Company | Yes | |
| 36 | Tri-State Generation & Transmission | Yes | |
| 37 | Western Area Power Administration | Yes | |
| 38 | Great River Energy | Yes | GRE believes that the new definition provides greater clarity with respect what does not constitute a compliance violation versus the previous version. |
| | **Response: The SDT thanks you for your comments and we are in agreement.** | | |
| 39 | CenterPoint Energy | Yes | No preference. |
| | **Response:** | | |
| 40 | Southern California Edison Company | Yes | SCE generally agrees with the information contained in Part 5 - Background. However, we question the value of placing a rationale within the body of the standard. SCE respectfully recommends that the revised "Background" information be added to the beginning of the "Guidelines and Technical Basis," which also includes explanations for various standard segments. |
| | **Response: The SDT thanks you for your comments. It is not specific to "force majeure" and is best answered in general comments.** | | |
| 41 | MRO's NERC Standards Review | Yes | The NSRS believes that the new definition provides greater clarity with respect what does not constitute a compliance violation versus the previous |

| | Organization | Yes or No | Question 2 Comment |
|---|---|---|---|
| | Subcommittee (nsrs) | | version. |
| | **Response: The SDT thanks you for your comments and we are in agreement.** | | |
| 42 | Tampa Electric Company | Yes | These changes add improved clarity and defintion to this section. |
| | **Response: The SDT thanks you for your comments and we are in agreement.** | | |
| 43 | Idaho Power | Yes | This will allow the utilities to address conditions that are within their control. |
| | **Response: The SDT thanks you for your comments and we are in agreement.** | | |
| 44 | FirstEnergy | Yes | While we agree with the changes proposed, we would recommend that the list contained in the "Other" section should be revised to include judicial actions such as injunctions. While this is not a natural occurring situation, it is certainly one that will prevent an entity from removing vegetation when needed or desired. |
| | **Response: The SDT thanks you for your comments. The “force majeure” provision is intended to recognize circumstances that are completely outside the TO’s control. Legal and judicial actions are certainly a barrier but there are other corrective actions available to mitigate such interference. The TO should be aware of such interference and should take whatever actions necessary, up to and including re-rating or de-energizing the line to avoid a vegetation conflict.** | | |
| 45 | BC Hydro | Yes | Yes but there should be more commentary around exceptions. You should get away from certain descriptive terms and be more empirical when you can to avoid ambiguity. For example “Fresh Gale” on the Beaufort Scale is not common as there are several variants to this scale and on some scales is defined as “Gale”. So do you mean winds of 39-46 mph (62-74 kmh) or greater wind speed? If so, why not state that? |
| | **Response: The SDT thanks you for your comments. The “force majeure” provision is not intended to address every possible exclusion but to be a general statement intended to recognize circumstances that are completely outside the TO’s control.** | | |

### 3. In response to comments received regarding the language in M1 and M2, the SDT modified the first bulleted item and added a sentence to the end of the paragraph in M1 and M2. Do you agree? Please explain.

**Summary Consideration:**

**Of 45 respondents, there are 2 abstentions, 27 are in agreement, and 16 are in disagreement.**

**The major comment issues raised are:**

1. **Definition of "qualified personnel".**
2. **Confusion around "real time observation of an encroachment into the MVCD" and documentation required to report a violation or attest that a violation did not occur. Also issues regarding an encroachment with no fault and/or momentary fault as being a violation.**

**The VM SDT considerations for the major comment issues are:**

1. **SDT changed the language to "confirmation by Transmission Owner".**
2. **Considered language proposed by Duke in comment 16 and adopted and modified by SDT.**

**A minor comment issue is:**

1. **The inclusion of examples in the requirement instead of the rationale box.**

**The VM SDT consideration for the minor comment issue is:**

1. **The SDT changed the language to "confirmation by Transmission Owner".**

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| 1 | MWDSC (METROPOLITAN | | |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| | WATER DISTRICT OF SOUTHERN CALIFORNIA) | | |
| 2 | Xcel Energy | | No comments/no position |
| 3 | GDS Associates | No | - Need to specify who qualifies as “qualified personnel” to observe the vegetation condition. |
| | **Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner.** | | |
| 4 | Hydro One | No | A clarification for M1 is needed regarding whether entities will have to attest to the fact that there has never been an encroachment in the MVCD. |
| | **Response: Thank you for your comment. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.** | | |
| 5 | Northeast Power Coordinating Council | No | A clarification for M1 is needed regarding whether entities will have to attest to the fact that there has never been an encroachment in the MVCD. |
| | **Response: Thank you for your comment. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.** | | |
| 6 | PPL Electric Utilities | No | As written M1 requires evaluation of condition by “qualified person” but no definition of qualified person given. Should be more direct and point to physical evidence of vegetation encroachment into MVCD, i.e. burned vegetation. |
| | **Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.** | | |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| 7 | CenterPoint Energy | No | CenterPoint Energy does not believe a performance based requirement should require evidence of processes and procedures to demonstrate compliance. However, if the majority of industry commenters agree with the SDT's approach, CenterPoint Energy has several concerns.Assuming R1.1 and R2.1 regarding observations of encroachments are not deleted from the Standard, then only the first paragraph regarding forms of evidence is helpful and necessary. The second paragraph is not relevant or necessary. The special qualification of Sustained Outage should be contained in R1 and R2, not M1 and M2. Also, the reference to a "Fault" in M1 and M2 instead of a "Sustained Outage" changes the scope of what is specified in R1 and R2 which is not reasonable. A "Fault" can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages. |
| | **Response: Thank you for your comment. The SDT chose the word "fault" as it is a NERC defined term. A fault associated with vegetation indicates that encroachment into the MVCD occurred.** | | |
| 8 | Arizona Public Service Company | No | Do not agree with real-time observation. Utility can use technology to determine all rated conditions if a tree related outage occurred. |
| | **Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement.** | | |
| 9 | MidAmerican Energy | No | Examples should be moved to the rationale boxes to avoid confusion on what is required and what is an example. All rationale boxes should have a disclaimer to the effect saying "For guidance only, not for enforcement". |
| | **Response: Thank you for your response. Examples were included in the Requirement at the response of NERC staff to add clarity. By definition, verbiage within the rationale boxes are for guidance and are not enforcable.** | | |
| 10 | Kansas City Power & Light | No | In response to the informal comment period, the SDT is clear that it believes the use of encroachment as a basis for determining the effectiveness and compliance of a vegetation management program. The purpose of this Standard is to identify the criteria for effective monitoring of vegetation in |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| | | | transmission right-of-way and to take appropriate actions when that monitoring identifies the need to "clear" vegetation to prevent potential transmission facility outages resulting from contact with vegetation. These proposed Measures as written do not give credit to the Transmission Owners for effectively monitoring their systems and taking appropriate actions in regard to vegetation clearing. Why does it make sense to punish and penalize a Transmission Owner for discovering an encroachment when they take the appropriate actions to remedy the condition before any facility outage occurs that results in compromising the reliability of the Bulk Electric System? These Measures and Standard should recognize the good practices of effective response to a vegetation condition and penalize ineffective response. Highly recommend the SDT consider including appropriate language to recognize effective remedial actions by Transmission Owners and by doing so, recognize effective efforts instead of punishing them.In addition, proving encroachments have not occurred will pose audit challenges in determining that encroachments have not occurred for the Auditors as well as Registered Entities. If no encroachments occur, then there is nothing to report or record. This is a weak platform to stand compliance on. Facility interruption events caused by vegetation contacts is definitively measurable and recordable. Recommend the SDT reconsider the concept of compliance with FAC-003 on the basis of sustained outages. |
| | **Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.** | | |
| 11 | BGE Forestry Management | No | M1 & M2 bullet: "Real-time observation of any MVCD encroachments." implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states;"To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading."However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| | | | immediately initiate an Immediate Threat Notification. Therefore, this measure has no value. |
| | **Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement.** | | |
| 12 | PNM | No | Needs a definition of Real Time Observations |
| | **Response: Thank you for your comment. The SDT believes that "Real Time" observations (the actual time during which the observation occurs) is sufficiently clear.** | | |
| 13 | Consumers Energy Company | No | None of the three examples of acceptable forms of evidence provided in the revision prove that a Transmission Owner actively managed vegetation to prevent encroachment into the MVCD. The Measure should require proof of active ROW clearing activity per the transmission vegetation management plan, such as invoicing or crew field reports or vegetation inspection data from the annual vegetation inspection. |
| | **Response: Thank you for your comment. The SDT would suggest you refer to R6 and R7, which addresses evidence of an annual vegetation inspection and work plan.** | | |
| 14 | BC Hydro | No | Overall, the definition of these measures is improved over draft 3. However, the standard should better define who a "qualified person" is and who has the authority to make attestations. R1 and R2 could be better defined relative to the standard definitions in section 4.2 as to what voltage levels in R2 are part of the standard and what is excluded. That is:R1 is any circuit that is an element of an IROL or WECC transfer path regardless of the transmission voltage.R2 is any circuit >200kV which is not an element of an IROL or WECC transfer path.Lower voltage circuits that do not fit the R1 definition are not part of this standard. |
| | **Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner. R1 and R2 intentionally differentiate between the components of the transmission system that are part of the IROL or WECC Transfer Path and the BES. The SDT believes that violations in the IROL or WECC Transfer Paths pose a greater risk of cascading events, and therefore carry higher VSLs.** | | |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| 15 | Central Maine Power Company, Iberdrola USA | No | Recommend SDT create two measures one measure if a tree violated the MVCD and no outage occurred and second measure and severity level if an outage occurred |
| | **Response: The SDT believes that enroachments into the MVCD where no fault occurs are a violation to the standard and should be included in R1 and R2.** | | |
| 16 | Duke Energy | No | The last sentence of this modification could be misinterpreted by a compliance representative to imply that all Faults must be investigated to eliminate or confirm vegetation as the cause of the fault. There are several sources (e.g. lightning, wind-blown debris) of Faults and several appropriate operational responses, some of which may not include field investigations, depending on the circumstances surrounding each Fault. Thus, the current wording is gray and should be modified to aid industry's understanding and thus to ensure compliance.The interpretation we suggest may not be obvious, but our experience with previous interpretations of certain facets of FAC-003-01 would indicate the need to better define the expectation.A potential modification to the last sentence of M1/M2 could be:If a later confirmation of a Fault by a qualified person shows that a vegetation encroachment within the MVCD has occurred, this shall be considered the equivalent of a Real-time observation. |
| | **Response: Thank you for your comment. The SDT agrees with your recommendation and has adopted the proposed language. The SDT believes that faults that occur on applicable lines included in R1 and R2 should be investigated to determine if the cause was vegetation related. If an entity can determine to their satisfaction, through documentable means such as through technology or other sources, that the fault was caused by some other reason (i.e. lightning), it is the entity's decision whether or not to investigate further.** | | |
| 17 | FPL Corporate Compliance | No | The measure is adding to the requirement. The measure should define how a requirement is met and not interpret or add to the requirement, otherwise this will add to confusion, instead of clarity, which should be the goal of any revised reliability Standard.Also, the measure implies that a fault investigation must be done. As written, momentary outages are included, and a fault investigation should not be required for momentary outage.It also places the same weight of violation on a momentary outage as it does a Sustained outage, which appears on its face not to appropriate nor |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| | | | necessary to meet the goal of FAC-003-2. In addition, an outage investigation is not a finite process that produces identical homogenous results every time. Of particular concern is the possibility that should a Transmission Owner have one or more momentary outages and not find the cause, then later have another outage (Sustained or Momentary), such a finding appears to lead to a multiple violation. This is inconsistent with focusing requirements on reliability risks to the bulk electric system. |
| | **Response: Thank you for your comment. A fault caused by the grow-in, fall-in, or blow-in of vegetation on the active right-of-way is a violation of the requirements regardless of whether the fault was momentary or sustained. Based on other comments, the SDT has modified the language in M1/M2.** | | |
| 18 | NERC Staff | No | With respect to both M1 and M2, NERC staff finds the "acceptable forms of evidence" incomplete. To assess compliance, the auditors would also need to see the processes and procedures identified under Requirement R3 and the annual work plan under Requirement R7 to see how the entity planned to prevent sustained outages and what the entity had done to implement that plan. Finally, what is the purpose of the following sentence?: "If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation." Recommend adding each report of a real-time observation of encroachment into the MVCD to the periodic data submittal. |
| | **Response: Thank you for your comment. The SDT believes that an attempt to list all "acceptable forms of evidence" would be difficult, as entities employ a myriad of documentation types. The SDT agrees that an auditor would need to see the processes and procedures indentified under R3 and R7 to perform an audit. An auditor with an understanding of vegetation management would be able to validate "acceptable forms of evidence" as part of compliance audit process. Real time observations of an encroachment into the MVCD is a violation of the standard and should be documented and self-reported. The RE's currently require periodic reporting.** | | |
| 19 | Allegheny Power | Yes | |
| 20 | Ameren | Yes | |
| 21 | American | Yes | |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| | Transmission Company | | |
| 22 | Bonneville Power Administration | Yes | |
| 23 | Consolidated Edison Company of New York Inc | Yes | |
| 24 | Dominion | Yes | |
| 25 | Exelon | Yes | |
| 26 | Idaho Power | Yes | |
| 27 | Idaho Power Company | Yes | |
| 28 | ITC Transmission | Yes | |
| 29 | Manitoba Hydro | Yes | |
| 30 | MRO’s NERC Standards Review Subcommittee (nsrs) | Yes | |
| 31 | Northeast Utilities | Yes | |
| 32 | Orange and Rockland Utilities, Inc. | Yes | |
| 33 | Pepco Holdings, Inc – Affiliates | Yes | |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| 34 | Progress Energy | Yes | |
| 35 | South Carolina and Gas | Yes | |
| 36 | Southern Company Transmission | Yes | |
| 37 | The United Illuminating Company | Yes | |
| 38 | Tri-State Generation & Transmission | Yes | |
| 39 | FirstEnergy | Yes | Although we agree with the language of M1 and M2 for the proposed R1 and R2 in the standard being balloted, we support the alternate versions of R1 and R2 (see comments in Question 6) and wish to see M1 and M2 developed for the alternate R1 and R2. |
| | **Response: Thank you for your comment.** | | |
| 40 | Great River Energy | Yes | GRE agrees with the revisions made to this standard since the last posting and requests clarification on what constitutes a qualified person. |
| | **Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner.** | | |
| 41 | Western Electricity Coordinating Council | Yes | however the statement of acceptable forms of evidence implies that a dated attestation alone could provide evidence of compliance. An attestation alone would not represent sufficient evidence to support a conclusion of compliance with encroachment limits only of the absence of an outage. |
| | **Response: Thank you for your comment. Real time observations of an encroachment into the MVCD is a violation of the standard and should be documented and self-reported.** | | |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| 42 | Western Area Power Administration | Yes | However, the last sentence added to the measure is imprecise and introduces undesirable subjectivity and confusion to the process for determining a compliance violation. |
| | **Response: Thank you for your comment. Based on the recommendation from several commentors, the last sentence in M1/M2 has been modified.** | | |
| 43 | Southern California Edison Company | Yes | SCE generally agrees with the revisions to M1 and M2, however we would suggest the last sentence of the second paragraphs in both M1 and M2 be modified to read: M1- Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault, by a qualified person, confirms that a vegetation encroachment, as described in R1 items 2-4 (above), occurred within the MVCD occurred, then it shall be considered a Real-time observation.M2- Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault, by a qualified person, confirms that a vegetation encroachment, as described in R2 items 2-4 (above), occurred within the MVCD occurred, then it shall be considered a Real-time observation. |
| | **Response: Thank you for your comment. Based on the recommendation from several commentors, the last sentence in M1/M2 has been modified.** | | |
| 44 | Tampa Electric Company | Yes | These changes allow for qualified review of field findings. |
| | **Response: Thank you for your comment.** | | |
| 45 | Entergy Services | Yes | We agree, IF the determination is made by a Qualified Person to have been caused by vegetation breaking the MVCD (if not breaking MVCD in real time when observed) based on close observation/inspection and hard evidence that a Flashover occurred, and that there is no evidence that the issues spotted on the tree were caused by environmental or biological symptoms or stressors of the tree in question. Hard evidence has to be present to classify |

| | Organization | Yes or No | Question 3 Comment |
|---|---|---|---|
| | | | the item as a vegetation outage if the tree is not within MVCD when the real time observation is made.....an assumption cannot be made that vegetation was the cause of an outage if the tree is situated at a distance that is greater than MVCD when observed unless there is hard evidence supporting the flashover as determined by a qualified person. |
| | **Response: Thank you for your comment.** | | |

## 4. In response to comments received that requirement R3 is deficient in detail, the SDT modified the requirement. Do you agree? Please explain.

**Summary Consideration:**

**Of 45 respondents, there are 32 in agreement, 12 in disagreement and1 abstention.**

**The major comment issues raised are:**

1. **The additional wording placed in the requirement after the first sentence adds confusion to the extent of documentation that will be required.**
2. **The use of the phrase "incorporate the dynamics" adds confusion to the requirement.**

**The VM SDT considerations for the major comment issues are:**

1. **The response pointed out that the reason that the additional wording was inserted was due to the numerous comments from the previous posting that the requirement needed more specificity.**
2. **The SDT agreed with some suggested wording to replace the phrase "incorporate the dynamics" and revised the requirement accordingly.**

**Some minor comment issues are:**

1. **One commenter questioned the use of the word "intent" in the rationale.**
2. **One commenter questioned the language of the measure.**
3. **One commenter was concerned that the removal of the programmatic details renders the requirement less auditable and questionably effective.**

**The VM SDT considerations for the minor comment issues are:**

1. **The wording in the rationale was changed to eliminate the word "intent".**
2. **In the response to the commenter questioning the language of the measure, the SDT explained that the focus of the measure is on the logic test of the Transmission Owner's vegetation maintenance program.**

**3. In response to the commenter concerned about the programmatic details being removed, the SDT responded by explaining various ways that this requirement could be audited and further explained the main focus of the requirement.**

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| 1 | MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA) | | |
| 2 | GDS Associates | No | - We suggest to eliminate / change the word “dynamics” because can create confusion with regards to the extent of documentation that has to be prepared.- Requirement should clearly state the criteria as in the maximum design (rating) or maximum operat |
| | **Response: The SDT thanks you for your comment. The intent of the more detailed wording of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. In light of your comment, and similar comments from others, the SDT has revised the wording of R3. We feel that this change will alleviate any perceived confusion.** | | |
| 3 | PPL Electric Utilities | No | As written, R3 now requires documentation of conductor dynamics as related to ratings and rated operational conditions. Not clear how this information is to be presented and documented and how vegetation conditions that exist are to be documented to provide evidence that management processes and procedures are adequate to prevent encroachment into MCVD. |
| | **Response: The SDT thanks you for your comment. The Technical Reference Document attempts to provide further explanation, along with examples, of how to present this information. While this information is not in the Standard itself, the supplemental information in the Technical Reference Document should help the Transmission Owner understand the SDT’s intent for the requirement. Also, The SDT has revised the wording in R3 and has removed the word “dynamics”.** | | |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| 4 | Great River Energy | No | GRE does not believe that the new specificity that has been added to R3 will improve the reliability of the BES. It is our opinion that the requirement would have been clearer if it had ended after the first sentence. The additional language after the first sentence does not improve clarity.In measures for other requirements the SDT has done a very good job of stating and clarifying (in their opinion) what acceptable forms of evidence are. M3 would benefit from this type of clarification. |
| | **Response: The SDT thanks you for your comment. The previous version of the Standard was crafted very much as you suggest. Many commenters disagreed with this approach, which led to the SDT crafting this more verbose version.** | | |
| 5 | Kansas City Power & Light | No | It is unclear that this requirement may utilize the industry practice of “ruling span” methods to determine the vegetation clearances for a transmission facility. “Ruling span” methods are used to determine the construction design for transmission facilities and includes maintaining safe clearance distances. This requirement could be interpreted as being applied to every individual span to determine vegetation clearances for a transmission facility which would not be practical. |
| | **Response: The SDT thanks you for your comment. The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. It leaves the decision to the Transmission Owner how to satisfy this “competency based” requirement. While a Transmission Owner could certainly take the approach that each individual span be addressed separately, it is also possible for a Transmission Owner to have a specific “vegetation maximum height” approach, based on the minimum ground clearance specification of an entire line. Either approach would satisfy this requirement.** | | |
| 6 | MidAmerican Energy | No | MidAmerican supports the additional detail the R3 should end after the first sentence. The additional detail should be moved to the rationale box as additional guidance. |
| | **Response: The SDT thanks you for your comment. If we understand your comment, the reason that R3 has greater detail was due to comments received after the last posting. The SDT felt compeled to add this additional information.** | | |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| 7 | Xcel Energy | No | R3 requires the Transmission Owner to have a documented process that shall contain certain items. Please bulletize these items for clarity.Additionally, the measure for this requirement indicates that the process document elements 'prevent' encroachment. It is presumed that the elements identified in the requirement are what need to be addressed in order to minimize the likelihood of encroachment. Essentially, M3 should be reworded to state "The procedures, processes, or specifications provided incorporate the elements identified in R3 (dynamics of a transmission line conductor's...) |
| | **Response: : The SDT thanks you for your comment. The SDT feels that the requirement is adequate in a non-bullet form. R3 has been revised to clarify the intent of this "competency based" requirement. The measure for this requirement should be a "logic" test looking at the methodology that the Transmission Owner uses in order to determine what vegetation actions need to take place. The Technical Reference Document gives examples of several ways to satisfy this requirement. The SDT feels that the measure as stated is adequate.** | | |
| 8 | Southern California Edison Company | No | SCE prefers the Draft 3 version of R3 which read:"Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROWs to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions."However, if the SDT believes it is prudent to revise R3 in response to certain commenters, SCE would respectfully recommend R3 be revised to read:"Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will account for the movement of transmission line conductors under their Rating and Rated Electrical Operating Conditions; and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines." |
| | **Response: The SDT thanks you for your comment. The SDT agrees that the wording in R3 should be modified. R3 has been revised to remove the reference to "incorporate the dynamics" and has recrafted the requirement wording similar to your latter recommendation.** | | |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| 9 | CenterPoint Energy | No | See response to Q3 above. However, assuming R3 is not revised to exclude processes and procedures, we have no preference to the wording between the two drafts. |
| | **Response: The SDT thanks you for your comment.** | | |
| 10 | Arizona Public Service Company | No | Still lacks detailed information. SDT needs to specify the documentation it is left up to interpretation by the utility. |
| | **Response: The SDT thanks you for your comment. The SDT feels that the combination of the requirement wording and the examples and explanations in the Technical Reference Document are sufficient detail to portray the intent.** | | |
| 11 | MRO's NERC Standards Review Subcommittee (nsrs) | No | The NSRS does not believe that the new specificity that has been added to R3 will improve the reliability of the BES. It is our opinion that the requirement would have been clearer if it had ended after the first sentence. The additional language after the first sentence does not improve clarity. The whole (as written) requirement may be interpreted as a requirement for "each span" of Transmission line to which the Requirement will be applied. In measures for other requirements the SDT has done a very good job of stating and clarifying (in their opinion) what acceptable forms of evidence are. M3 would benefit from this type of clarification. |
| | **Response: The SDT thanks you for your comment. The previous version of the Standard was crafted very much as you suggest. Many commenters disagreed with this approach, which led to the SDT to address this issue by adding the specificity.**<br>**R3 is a "competency based" requirement. The measure should be whether the methodology used by the TO to maintain vegetation passes the basic logic test. (eg: Our max growth rate is 3' per year. We have a minimum ground clearance spec for 230 kV of 24 feet at maximum sag. We maintain the lines every three years. During maintenance of 230 kV lines we remove all vegetation over 11.5 feet high) For a "results based" standard, the emphasis should be on the Tranmssion Owner demonstrating competency in its approach, however simple or complex that approach may be** | | |
| 12 | NERC Staff | No | The removal of programmatic details from R3 renders the auditing task much more difficult. How does one assess the quality of the program except |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| | | | through the results required in R1 and R2? Since maintaining specific cut-to clearances is not required, there is much greater subjectivity in application that greatly complicates the auditor job. If the team does not want to limit the available approaches, it could provide flexibility by offering an array of deterministic formulas or approaches for maintaining vegetation. This might include maintaining vegetation to remain within a certain height from the ground given maximum sag distances.<br><br>Additionally, this requirement does not seem to require the entity to actually follow its policies and procedures (unlike, for instance, R7). What is a violation here? Not having the documented procedure(s) OR whether the documented procedure(s) actually demonstrate that the entity can prevent encroachment?<br><br>NERC staff is also concerned with some of the language in M3. Consider the following modification: “The Transmission Owner will have procedures, processes, or specifications as identified in Requirement R3, records showing work done to support its annual work plan identified in Requirement R7, and its quarterly vegetation reports, to demonstrate that it can prevent encroachment into the MVCD.”<br><br>Finally, with respect to the Rationale associated with R3, how would NERC enforce poor intent or a poor indication of competency (especially if the entity was performing well)? Recommend: Provide a basis for evaluating whether the Transmission Owner’s procedures, processes, or specifications used to maintaining vegetation are achieving that goal. There may be many acceptable approaches to controlling vegetation so that it does not encroach into the MVCD.<br><br>And one small copyedit: “interrelationships” should not have a hyphen. |
| | **Response: The SDT thanks you for your comment.** | | |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| | **Regarding the comments pertaining to the requirement wording: The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates an understanding of the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. The SDT points out that inclusion of a programatic list of activities by itself does nothing to to ensure reliability. R3 is a competency based requirement. The audit test is simply one of logic. Does the methodology the TO conveys in R3 logically ensure that no encroachments into the MVCD occur? The SDT feels that it is important for the Transmission Owner to have the flexiblity to choose how it satisfies this requirement and not to provide a limited menu of approaches that could be used. (eg: Our max growth rate is 3' per year. We have a minimum ground clearance spec for 230 kV of 24 feet at maximum sag. We maintain the lines every three years. During maintenance of 230 kV lines we remove all vegetation over 11.5 feet high) For a "results based" standard, the emphasis should be on the Tranmssion Owner demonstrating competency in its approach, however simple or complex that approach may be. The violation for this requirement would be either the TO failed to specify its approach or that the approach specified does not pass the logic test.**<br><br>**Regarding the comments pertaining to the measures M3: The SDT feels that an auditor knowledgeable of utility vegetation management work would be capable to evaluate if a well documented approach is sufficient to ensure no vegetation encroachments into the MVCD.**<br><br>**Regarding the comments pertaining to the Rationale: The drafting team agrees that "intent" is not measurable or enforceable and has removed it from the rationale. The evaluation and measurement of the competency is listed above.** | | |
| 13 | Consumers Energy Company | No | This really is another attempt at avoiding defining a minimum clearance specification and is not practical. As written, this would require each Transmission Owner to define and document the procedures, processes or specification by individual span for every line owned or operated by the Transmission Owner. Each span varies in length and profile and a single line may have several different conductor types with different load ratings. Line loadings will vary along the line based on substation taps, etc. The dynamics described in the language could only be done on an individual span basis to be reasonably accurate. This is not practical from a planning standpoint or from a standpoint of implementing clearing work in the field. |
| | **Response: The SDT thanks you for your comment. The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. It leaves the decision to the Transmission Owner how to satisfy this** | | |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| | **"competency based" requirement. While a Transmission Owner could certainly take the approach that each individual span be addressed separately, it is also possible for a Transmission Owner to have a specific "vegetation maximum height" approach based on the minimum ground clearance specification of an entire line. Either extreme would satisfy this requirement. A Transmission Owner also could have an approach that contained a mixture of the two extremes.** | | |
| 14 | Allegheny Power | Yes | |
| 15 | Ameren | Yes | |
| 16 | American Transmission Company | Yes | |
| 17 | BGE Forestry Management | Yes | |
| 18 | Bonneville Power Administration | Yes | |
| 19 | Central Maine Power Company, Iberdrola USA | Yes | |
| 20 | Consolidated Edison Company of New York Inc | Yes | |
| 21 | FPL Corporate Compliance | Yes | |
| 22 | Duke Energy | Yes | |
| 23 | Entergy Services | Yes | |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| 24 | Exelon | Yes | |
| 25 | FirstEnergy | Yes | |
| 26 | Hydro One | Yes | |
| 27 | Idaho Power | Yes | |
| 28 | Idaho Power Company | Yes | |
| 29 | ITC Transmission | Yes | |
| 30 | Manitoba Hydro | Yes | |
| 31 | Northeast Power Coordinating Council | Yes | |
| 32 | Northeast Utilities | Yes | |
| 33 | Orange and Rockland Utilities, Inc. | Yes | |
| 34 | Pepco Holdings, Inc - Affiliates | Yes | |
| 35 | PNM | Yes | |
| 36 | Progress Energy | Yes | |
| 37 | South Carolina and Gas | Yes | |
| 38 | The United | Yes | |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| | Illuminating Company | | |
| 39 | Tri-State Generation & Transmission | Yes | |
| 40 | Western Area Power Administration | Yes | |
| 41 | Western Electricity Coordinating Council | Yes | |
| | **Response:** | | |
| 42 | Dominion | Yes | Although we agree with the intent of the proposed language, we feel the requirement should be revised to read:Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such procedures, processes, or specifications shall consider the dynamics of a transmission line conductor's movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines. |
| | **Response: The SDT thanks you for your comment. The SDT agrees that the wording in R3 should be modified. R3 has been revised to remove the reference to "incorporate the dynamics" and has recrafted the requirement wording similar to your latter recommendation.** | | |
| 43 | BC Hydro | Yes | As a competency requirement, R3 seems to be missing any requirement for a utility to define who is qualified to develop these plans, which is a departure from FAC-003-1 R1.3. I think that the utility should in their standards define who is qualified to develop their transmission vegetation management program |
| | **Response: The SDT thanks you for your comment. While the SDT agrees that personnel qualifications are important in any pursuit for perfection, the overall approach for this version of the Standard is a "results based' product. In light of that, the SDT does not feel that a "fill in the blank" requirement for personnel** | | |

| | Organization | Yes or No | Question 4 Comment |
|---|---|---|---|
| | **qualifications is necessary.** | | |
| 44 | Tampa Electric Company | Yes | This better clarifies section R3 |
| | **Response:** | | |
| 45 | Southern Company Transmission | Yes | While voting yes we are concerned about the interpretation of the expanded verbiage, how much documentation will be enough. |
| | **Response: The SDT thanks you for your comment. The Technical Reference Document attempts to provide further explanation, along with examples, of how to present this information. While these examples are not in the Standard itself, the supplemental information in the Technical Reference Document should help the Transmission Owner understand the SDT's intent for the requirement, and therefore the documentation required to demonstrate competency.** | | |

## 5. In response to comments received that requirement R7 is unclear with respect to flexible work plans, the SDT modified the requirement. Do you agree? Please explain.

**Summary Consideration:**

**Of 45 respondents, there are 2 abstentions, 34 are in agreement, and 9 are in disagreement.**

**The major comment issues raised by those in disagreement are:**

1. **The Requirement is vague and needs more specificity and explanation.**
   - **Does not require development of the Annual Vegetation Work Plan**
   - **Language allowing modifications to the Work Plan should specifically require documentation of changes**
   - **M7 is measuring completion of Work Plan, not prevention of encroachments into the MVCD**
   - **The phrase "…provided they do not put the transmission system at risk of a vegetation encroachment" could be better written as "…they do not allow encroachment of vegetation into the MVCD"**
2. **Examples describing potential reasons for plan modification should be clarified or eliminated.**
   - **Decreases in funding not valid.**
   - **Encroachments due to Major Storms are exempted in Footnote 2. R7 allows modification to Plan due to major storms but does not allow encroachments associated with plan change.**
   - **Generally. the examples identified are broad in nature**

**Some minor comment issues are:**

1. **Eliminate requirement or use the first sentence only.**
2. **Some concern with lack of agreement of language with other parts of the Standard.**

**The VM SDT appreciated both the major and minor comment issues identified but decided that the requirement and measures are appropriate and clear as currently written and did not modify any of the language. The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the MVCD. In addition, as expressed in the Rationale, R7 sets the expectation that the work identified in the**

**annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner's work plan with this measure.**

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| 1 | GDS Associates | | |
| 2 | MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA) | | |
| 3 | Western Area Power Administration | No | As the list of "examples of reasons for modification" is not all inclusive, it is unnecessary and could result in confusion regarding compliance when a scenario other than one listed requires a change. Further, documentation of changes to the annual plan adds unnecessary administrative burden which is inconsistent with a performance based standards approach. |
| | **Response: Thank you for your response. The SDT feels the list of examples, while not all inclusive, is helpful to the TO in determining how and when to apply flexibility to its annual plan, when required. It is important the TO documents modefication to the plan to insure the work not completed during that period is carried over and completed within a reasonable time frame.** | | |
| 4 | Ameren | No | Funding Adjustments (increase or decrease) - need more description to imply only when planned vegetation work is "over and above". |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| | **Response: Thank you for your comment. The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modefying the Annual Plan keeping in mind that a modefication must not place the transmission system at risk of vegetation encroachement into the MVCD.** | | |
| 5 | MidAmerican Energy | No | MidAmerican supports the additional detail. However R7 should end after the first sentence. All additional material should be moved to the rationale box. |
| | **Response: Thank you for your comment. The position of the SDT is to have this langiage in the requirement such to allow for flexibility to the work plan. Keep in mind Rationale language is clarifying documentation and not enforcable. The SDT feels it is important that the TO have the flexibility to revise its Annual Plan which is subject to many issues that can influence the completion of work.** | | |
| 6 | The United Illuminating Company | No | R1 and R2 are requirements that no encroachment occurs. R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; which is very different from ensuring no encroachment. In the Reference for R7 the word “ensure” is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System.M7 is measuring work plan completion not the prevention of encroachment. United Illuminating suggests that R7 be changed to: Each Transmission Owner shall complete the work in an annual vegetation work plan to manage the prevention of vegetation encroachments occur within the MVCD. In this way, a violation of R1/R2 does not necessarily mean R7 is violated. The entity does not avoid a penalty for an encroachment because a violation of R1/R2 occurs for actual encroachment. If an encroachment occurs the compliance enforcement authority can review the entities vegetation management plan to determine if it is compliance with R7/M7. |
| | **Response: Thank you for your comments. As expressed in the Rationale, R7 sets the expectation that the work identified in the annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of** | | |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| | **the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner's work plan with this measure.** | | |
| 7 | CenterPoint Energy | No | See response to Q3 above.However, assuming R7 is not revised to exclude processes and procedures, the new wording is preferred since it is more specific.  Additionally, a new ambiguous phrase is introduced, "provided they do not put the transmission system at risk of a vegetation encroachment", which we recommend to be changed to more specific wording, "provided they do not allow encroachment of vegetation into the MVCD". |
| | **Response:  Thank you for your comments.  The SDT felt the language was appropriate.** | | |
| 8 | Southern Company Transmission | No | The first sentence of the Requirement 7 Rationale conflicts with the second sentence. The R7 Rationale should be reworded as follows:"This requirement sets the expectation that the work identified in the annual work plan should be completed as planned.  However, an annual vegetation work plan must allow for work to be modified in response to changing conditions. These modifications must take into consideration the anticipated growth of vegetation and all other environmental factors, provided that the changes do not cause a vegetation encroachment within the MVCD." |
| | **Response:  Thank you for your comments.  The SDT felt the language was appropriate.** | | |
| 9 | NERC Staff | No | This is the first instance in which an annual work plan is discussed. It would appear necessary to first develop an annual work plan component of the overall vegetation management program. There should also be some performance review or expectation that the annual plan as implemented achieved the intended program objectives, or that modifications would be necessary.<br><br>Does R7 require both that a Transmission Owner has an annual vegetation |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| | | | work plan AND that it completes the work plan? Detail is required as to what is expected in the work plan, as there is currently no basis to judge whether the work plan is adequate or not adequate. And what does a modification entail? Does this mean reduction of performance, delay in performance, or complete postponement of performance?<br><br>NERC staff is also concerned with the list of examples one might use to modify an annual plan. Several of these items should not pose any greater risk to vegetation contact and render the requirement virtually unenforceable. It provides a wide array of reasons to postpone vegetation management and may make it a very low priority for an entity:<br>• "Rescheduling work between growing seasons": This could be an honest change (if there are unexpected seasonal changes) or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating.<br>• "Crew or contractor availability": This could be an honest change (if there is an unexpected labor dispute or if crews are needed to help a neighboring utility during an unexpected emergency) or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. Alternatively, it could be removed from the list as it is within the exclusive control of the Transmission Owner.<br>• "Identified unanticipated high priority work": This could be an honest change or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. It is also vague and would necessitate a judgment call for enforcement.<br>• "Permitting delays": Annual plans should account for anticipated permitting schedules and maybe even add a factor for uncertainty. It is a planning issue for the entity and should not be an acceptable excuse for not conducting vegetation management.<br>• "Land ownership changed": If a landowner has the ability to affect the reliability of the bulk power system, the landowner should be subject to |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| | | | the reliability standards. A registered entity should be responsible for the land in its ROW, especially if it has turned control of the land, and the ability to affect reliability of the BPS, over to another entity or person for financial gain.<br>• “Funding adjustments”: NERC staff is not convinced that this is a legitimate reason for adjusting an annual vegetation work plan. Economic considerations should not be a reason to delay or modify vegetation management.<br>• “Emerging technologies”: It is unclear what this example is intended to accomplish.<br><br>In general, these examples should be bounded in some way to ensure that a modification due to one of their occurrences does not impart a greater risk of vegetation contact. |
| | **Response: Thank you for your comments. Per the SDT, developing the annual work plan is an understood requirement in order for the TO to complete the work plan. Thus, a requirement to develop the plan is not needed. R3 specifies the processes, procedures and/or specifications that are utilized by a TO to prevent an encroachment of the MVCD. This “Competency Based” requirement sets the core foundation that a TO will utilize to develop their annual work plan.**<br>**As expressed in the Rationale, R7 sets the expectation that the work identified in the annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner’s work plan with this measure.**<br>**By bounding the flexibility as advocated, there are several variables involved such it makes it impractical to be able to address the many operational scenerios that a TO may experience. Thus, without being very prescriptive, the SDT feels that it is best to provide general guidance to what are valid modifications to the work plan.** | | |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| 10 | Kansas City Power & Light | No | This requirement is in direct conflict with the “exclusions” as described in section 4.4. Section 4.4 makes it clear that effects of “major storms” on a vegetation programs efforts will be allowed as an exclusion toward compliance with these requirements, yet, R7 does not allow any encroachment due to modifications to a vegetation plans efforts due the “Major Storms” (second bullet) or “Weather conditions/Accessibility” (bullet 6). Please explain what is intended here that is different than what was intended in section 4.4.In addition, this presents some audit difficulties regarding the notion of detecting a “modified work plan”. Once a work plan is altered and new objectives are laid out, that becomes the plan and the plans that were replaced may be discarded since they would be of no value. Further, what difference does it make to track or monitor any changes to a work plan provided effective vegetation management is maintained? Recommend the SDT consider removing the language regarding “work plan flexibility” as this may suggest and impose an unnecessary compliance burden on Registered Entities and Auditors. |
| | **Response: Thank you for your comments. The SDT views Major Storms in the list of examples differently than in Footnote 2. The example has more to do with schedules being revised as a result of a major storm while Footnote 2 refers to issues of sustained outages caused by circumstanses beyond the control of the Transmission Owner, and excepting resulting violations to the standard.**<br><br>**The SDT feels it is important to track and document changes in the work plan to insure rescheduled work is completed at some later date. Work plan flexibility through modification to the work plan is critical and must be recognized so that the Transmission Owner can propertly plan and revise work schedules when necessary.** | | |
| 11 | Xcel Energy | No | What exactly does complete an annual work plan mean? It infers that an annual work plan must be developed/documented and executed. If this is the case, then clearly state as such.In general, R6 & R7 go against the grain of the results based standard concept. R1 already established that the Transmission Owner cannot have encroachment. R3 requires annual inspection (essentially establishing the plan). Why replicate in R6 & R7, it does not seem to serve any useful purpose. |
| | **Response: Thank you for your comments. As stated in the Rationale, “This requirement sets the expectations that the work identified in the annual work plan will be completed as planned.” Because the** | | |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| | **work plan is recurring in nature, a new work plan must be developed each year to state work planned for that period. This requirement directly supports Requirement 3 which calls for a documented vegetation management approach to prevent MVCD encroachments.** | | |
| 12 | Allegheny Power | Yes | |
| 13 | American Transmission Company | Yes | |
| 14 | Arizona Public Service Company | Yes | |
| 15 | BGE Forestry Management | Yes | |
| 16 | Bonneville Power Administration | Yes | |
| 17 | Central Maine Power Company, Iberdrola USA | Yes | |
| 18 | Consolidated Edison Company of New York Inc | Yes | |
| 19 | Consumers Energy Company | Yes | |
| 20 | FPL Corporate Compliance | Yes | |
| 21 | Dominion | Yes | |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| 22 | Duke Energy | Yes | |
| 23 | Entergy Services | Yes | |
| 24 | Exelon | Yes | |
| 25 | FirstEnergy | Yes | |
| 26 | Great River Energy | Yes | |
| 27 | Hydro One | Yes | |
| 28 | Idaho Power | Yes | |
| 29 | Idaho Power Company | Yes | |
| 30 | ITC Transmission | Yes | |
| 31 | Manitoba Hydro | Yes | |
| 32 | Northeast Power Coordinating Council | Yes | |
| 33 | Northeast Utilities | Yes | |
| 34 | Orange and Rockland Utilities, Inc. | Yes | |
| 35 | Pepco Holdings, Inc - Affiliates | Yes | |
| 36 | PNM | Yes | |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| 37 | PPL Electric Utilities | Yes | |
| 38 | Progress Energy | Yes | |
| 39 | South Carolina and Gas | Yes | |
| 40 | Tri-State Generation & Transmission | Yes | |
| 41 | Western Electricity Coordinating Council | Yes | annual vegetation management plans must have some flexibility. If the TO has the authority to create the plan they should have the authority to modify the plan. The key point is that changes, particularly delays to planned work would have to be approved. Do not believe “decreases in funding” should be listed as a valid reason for modification of work plan related to a reliability standard.From an enforcement viewpoint, there is ambiguity or perceived ambiguity in “provided they do not put the transmission system at risk of a vegetation encroachment.” Provided the potential that there may never be a self-report addressing this violation. |
| | **Response: Thank you for your comments. The SDT agrees the plan needs flexibility and the Transmission Owner has authority for plan oversite. No approval for changes is called for in the requirement, but documentation is required to note the change.**<br>**The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the MVCD.** | | |
| 42 | Southern California Edison Company | Yes | SCE agrees with the revisions to R7, but notes the some minor edits to the text are still needed. |
| | **Response: Thank you for your comments. The SDT felt the language was appropriate.** | | |
| 43 | MRO’s NERC Standards Review Subcommittee (nsrs) | Yes | The NSRS has issue with the word “may” (and its components along with the associated bulleted points) and recommends that it is removed and placed in the rational box. |

| | Organization | Yes or No | Question 5 Comment |
|---|---|---|---|
| | **Response: Thank you for your comments. The SDT believes the requirement as written is needed to insure flexibility of work plan.** | | |
| 44 | BC Hydro | Yes | The requirement as currently worded, seems to assume but does not explicitly state that a utility must prepare and document an annual vegetation work plan and document in some manner any modifications to that work plan as they occur. The work plan change documentation should include any risks of work deferral and mitigation plans to address those risks if there are any. |
| | **Response: Thank you for your comments. Per the SDT, developing the annual work plan is an understood requirement in order for the TO to complete the work plan. Thus, a requirement to develop the plan is not needed. R3 specifies the processes, procedures and/or specifications that are utilized by a TO to prevent an encroachment of the MVCD. This "Competency Based" requirement sets the core foundation that a TO will utilize to develop their annual work plan.**<br>**The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the TO to manage the quality of the work plan and mitigate any risk to the system associated with modifications to the work plan.** | | |
| 45 | Tampa Electric Company | Yes | These changes add greater clarity, as well as real world examples, to this standard. |
| | **Response: Thank you for your comments.** | | |

**6. In response to comments received that requirement R1/R2 may not adequately protect the transmission conductors under all conditions of sag and sway, the SDT drafted alternate language for the industry to provide feedback. The SDT did not opt to incorporate this language into "Draft 4" until further comment was solicited from industry. Which do you prefer? Please comment on your choice in the comment box below:**

*"**Alternate R1/R2.** Each Transmission Owner shall manage the floor of its Active Transmission Line ROW in accordance to one of the following at all times:*

*A) A fixed maximum vegetation height of 15 feet from the ground at the mid-half of the span and 20 feet in the outside quarters of the span, or,*

*B) A calculated maximum vegetation height that is the difference between the minimum conductor height at "max sag" minus MVCD minus cycle growth, or,*

*C) A calculated minimum vegetation to conductor clearance that is the sum of "max sag" in the span plus MVCD plus cycle growth, or,*

*D) A value determined by the Transmission Owner to provide a separation between the conductor and the vegetation that is comparable to options A, B, or C.*

*E) Any alternative approach that ensures no encroachment occurs within MVCD, considering the sag and sway of the conductor throughout its operating range under rated conditions.*

*F) A value to provide a separation between the conductor and the vegetation that is the sum of MVCD, and a value that considers the sag and sway of the conductor throughout its operating range under rated conditions plus 10 feet."*

*NOTE: The SDT suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this Alternate R1/R2.*

**Summary Consideration:**

**Of 45 respondents, there are 4 abstentions (expressed no preference for Draft or Alternate), 16 (two of which appear to be from the same company) are in agreement (that Alternate Language is preferred), and 25 are in disagreement (that Alternate is preferable, liking Draft language better).**

**The major comment issue raised is:**

**1. The only real issue raised in the comments by the 41 respondents that had a preference was that of the style of Requirement language appropriate for an RBS standard. Both groups agreed that either the Draft or Alternate language addressed the root requirement(s). In fact, respondents in both groups indicated that Option E**

**of the Alternate language was in essence the Draft language. (And of those in Alternate group that discussed the 6 options, E was the clear favorite, receiving five (5) mentions with A and C only receiving one (1).)**

**However, those that preferred the Alternate language cited that written in the form proposed by the Alternate language, the Requirements R1/R2 would provide much more flexibility and two respondents even cited that the Alternate allowed Transmission Owners to specify their own clearances.**

**For those voting for the Draft language (the majority), the most common reason cited was Draft language was less prescriptive. The second most common reason cited was that the Alternate Language would be confusing. And a couple commenters in this group opined that the Alternate language appeared to be “fill-in-the-blanks” language.**

**The VM SDT consideration for the major comment issue is:**

1. **Based on the “vote” the team will retain the Draft language. Also, Option E was cited most often by the Alternate group as the most desirable of the options and is in fact essentially the Draft language. The SDT was additionally swayed by the comments about confusion and fill-in-the-blanks as two overriding premises behind the standards should be clarity and acceptance by FERC.**

**A minor comment issue is:**

1. **Commenters offered several minor wording changes to the Draft language.**

**The VM SDT consideration for the minor comment issue is:**

1. **The team has incorporated some of these minor wording changes and rejected others when the change was found to introduce other problems.**

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| 1 | MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA) | | |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| 2 | Progress Energy | | |
| 3 | South Carolina and Gas | | |
| 4 | Arizona Public Service Company | | Neither version is acceptable ANSI-A300 part 7 should be included here. Having set distances will give federal agencies the ability to minimize a utilities TVMP. |
| | **Response: The SDT thanks you for your comments. The team appreciates your concern about federal agencies and other landowners' interpretation of the Requirement to impede vegetation management but is not swayed that the language currently in the Draft version suffers from a set distance specification as you cited.** | | |
| 5 | Bonneville Power Administration | Alternate version of R1/R2 | |
| 6 | Central Maine Power Company, Iberdrola USA | Alternate version of R1/R2 | |
| 7 | PNM | Alternate version of R1/R2 | |
| 8 | GDS Associates | Alternate version of R1/R2 | - E) seem more appropriate. The alternate R1/R2 standard requirements shall reduce the number of possibilities and simplify the criteria towards the design / operating conditions and additional standards ought to be considered in concert with current stan |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 9 | Allegheny Power | Alternate version of R1/R2 | Allegheny Power prefers the alternate version. |
| | **The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which** | | |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | **may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 10 | PPL Electric Utilities | Alternate version of R1/R2 | Alternate C provides assurances that growth rates, maintenance cycle, and max-sag are taken into consideration. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft because the SDT believes it already addresses the provisions you state, i.e. growth rates, maintenance cycle, etc.** | | |
| 11 | Hydro One | Alternate version of R1/R2 | Alternate Version E would allow a Transmission Owner to use an approach consistent with the current version of FAC-003 by defining a minimum clearance distance and a vegetation management clearance distance. This approach has met the objectives of FAC-003 since 2006. Use of version E would change the standard from a prescriptive approach to a Transmission Owner defined approach. In addition, Alternate Version E is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 12 | Northeast Power Coordinating | Alternate version of R1/R2 | Alternate Version E would allow a Transmission Owner to use an approach consistent with the current version of FAC-003 by defining a |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | Council | | minimum clearance distance and a vegetation management clearance distance. This approach has met the objectives of FAC-003 since 2006. Use of version E would change the standard from a prescriptive approach to a Transmission Owner defined approach. In addition, Alternate Version E is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 13 | Idaho Power | Alternate version of R1/R2 | Alternative R1/R2 allows the utility to maintain adequate clearances with their preferred approach. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 14 | FirstEnergy | Alternate version of R1/R2 | Although we agree with the alternate version of R1/R2, we have the following comments:1. We assume that R1 and R2 will be written similar to the current proposal with regard to IROL (High VRF) and non-IROL (Medium VRF) transmission lines, respectively. This should be clear after changes have been made to the standard before the final ballot.2. Although the SDT states that it "suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this alternate R1/R2", we are not clear how these measures will be written and would like to see a draft of the measures so we can review and |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | | | comment.3. The alternate requirements appear to be "planning" in nature instead of "real-time"; we assume the intention of the SDT was the latter. Therefore the requirements should be revised with language that is "real-time" in nature. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 15 | BGE Forestry Management | Alternate version of R1/R2 | BGE believes R1/R2 should contain language that ensures that vegetation is manage taking into account sag and sway throughout the conductors operating range as the alternate language above outlines. The six options proposed allows the Transmission Owner the flexability needed to manage the active ROW a varity of ways and at the same time ensures the reliable operation the Bulk Electric System with respect to vegetation. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft because the SDT believes it already addresses the provisions you state, i.e. sag and sway.** | | |
| 16 | Idaho Power Company | Alternate version of R1/R2 | I think this gives us more flexibility to maintain our clearances. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 17 | Northeast Utilities | Alternate version of R1/R2 | Option E above is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | | | performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 18 | Consumers Energy Company | Alternate version of R1/R2 | Prefer Alternative A |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.** | | |
| 19 | Kansas City Power & Light | Alternate version of R1/R2 | Prefer Alternative E from the list above. Please clarify the meaning of sway in Alternative E. Is that wind blowout? |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft. Sway is synonymous with wind blowout in Alternative E. Please refer to the Technical Reference document for further clarification on this issue.** | | |
| 20 | Southern California Edison Company | Alternate version of R1/R2 | SCE prefers the operational flexibility provided by the alternate version of R1/R2. We also note that dating back to development of FAC-003-1 and related comment periods, Transmission Owners have repeatedly stated that a “one-size-fits-all” TVMP is not viable or reasonable. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of** | | |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | **commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft. The SDT completely agrees with your comment about the 'one-size-fits-all' issue. The SDT has struggled with the proper wording that would allow each Transmission Owner the flexibility necessary to minimize the risk of vegetation outages while adapting to their unique vegetation challenges in a cost-effective-to-consumers manner. The SDT would encourage you, in future comment periods, to offer specific wording that will address the deficiencies you identified and what persuaded you to choose the Alternate version of R1/R2 as the preferred version.** | | |
| 21 | Ameren | Draft 4 version of R1/R2 | |
| 22 | Duke Energy | Draft 4 version of R1/R2 | |
| 23 | Exelon | Draft 4 version of R1/R2 | |
| 24 | Great River Energy | Draft 4 version of R1/R2 | |
| 25 | ITC Transmission | Draft 4 version of R1/R2 | |
| 26 | MidAmerican Energy | Draft 4 version of R1/R2 | |
| 27 | Pepco Holdings, Inc - Affiliates | Draft 4 version of R1/R2 | |
| 28 | Tri-State Generation & Transmission | Draft 4 version of R1/R2 | |
| 29 | Xcel Energy | Draft 4 version of R1/R2 | Any of the alternate versions would amplify or create issues between land owners and Transmission Owners and are contrary to concepts of Integrated Vegetation Management, in particular, best management practices. |
| | **Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT** | | |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | **has opted to retain the language in the current draft, in part because of the confusion you cited.** | | |
| 30 | American Transmission Company | Draft 4 version of R1/R2 | ATC feels that Draft 4 Version of R1/R2 is the preferred version. The Alternate version is too prescriptive and has little flexability. |
| | **Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT has opted to retain the language in the current draft; in part because of the prescriptive nature of the Alternate versions that you mentioned as well as it being noted as confusing.** | | |
| 31 | CenterPoint Energy | Draft 4 version of R1/R2 | CenterPoint Energy does not believe a performance based requirement should be this prescriptive. However, if the majority of industry commenters agree with the SDT's approach, CenterPoint Energy has several concerns. The terminology, "operating within Rating and Rated Electrical Operating Conditions" is sufficiently definitive. There is no need to be more prescriptive. Alternate R1/R2 (E) is already similar to the Draft 4 wording. Of the two alternative, we recommend keeping the Draft 4 wording as is; however, we recommend moving the applicability of transmission line ratings to the Applicability section of the Standard as "4.5 Other: The Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the Rating and Rated Electrical Operating Conditions of the Facilities defined in 4.2." These conditions should be applicable to all elements and requirements of the Standard just as the force majeure statement does. |
| | **Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature you mentioned as well as it being noted as confusing. The SDT has considered your excellent suggestion about the Applicability Section. However, after extensive discussion, the SDT opted not to add the language in the Applicability Section as the NERC framework for Applicability Sections seems to guide against it.** | | |
| 32 | Consolidated Edison Company of New York Inc | Draft 4 version of R1/R2 | Consolidated Edison Company of New York, Inc prefers the Draft 4 version. The wording in the VSLs should be modified for both Requirements to include the phrase 'manage vegetation'. The phrase 'manage vegetation' requires a utility to take specific action to prevent encroachments/outages. |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | **Response: The SDT thanks you for your comments. The SDT has considered your excellent suggestion about the VSLs and decided to change the Requirements in the manner you describe.** | | |
| 33 | Entergy Services | Draft 4 version of R1/R2 | Draft 4 is acceptable, but if alternate language is chosen, it should be similar to option E, keeping the determination simple and with as few variables for interpretation as necessary. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore the team has decided to retain the language in the current draft.** | | |
| 34 | Western Electricity Coordinating Council | Draft 4 version of R1/R2 | Draft 4 should be sufficient. If industry believes MVCD is not adequate then the tables for MVCD should be modified to account for sag and sway. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the Alternate language confusing and potentially to be fill-in-the-blanks. Therefore the team has decided to retain the language in the current draft. The SDT is convinced that the technically defensible MVCD is adequate but appreciates the helpful suggestion nonetheless.** | | |
| 35 | Manitoba Hydro | Draft 4 version of R1/R2 | I would suggest adding verbage to the draft 4 version to explicitly include the sag and sway of the conductor to the concept of "operating within rating and electrical operating condition" |
| | **Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature you mentioned as well as it being noted as confusing. The SDT has considered your thoughtful and helpful suggestion about the explicit language which could be added to the Requirement to make it stand-alone and not rely on the Technical Reference document. The SDT, however, decided not to add the suggested verbiage because the team felt that the Rationale Box addressed this issue and the Requirement, if modified, would become somewhat confusing.** | | |
| 36 | MRO's NERC Standards Review | Draft 4 version of R1/R2 | It is the NSRS's opinion that that the requirement as currently written in version 4 is consistent with the intent of a standard; i.e. stating what is |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | Subcommittee (nsrs) | | required as opposed to stating how to achieve what is required. |
| | **Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature of the alternate that you cited, as well as it being noted as confusing.** | | |
| 37 | NERC Staff | Draft 4 version of R1/R2 | NERC staff supports the Draft 4 version. The six options listed in the alternative version of R1/R2 do not seem manageable from a utility perspective. But while staff prefers the existing language, it continues to emphasize that fall-ins from outside the ROW can impact the line and need to be taken into consideration. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offered many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters, including you, find the alternate language confusing and some even cite that it may potentially be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current draft. Although the SDT understands that fall ins from off-ROW trees can negatively impact the lines and a sound TVMP would include a program to address these potential issues, it is not appropriate that off-ROW trees be included in a NERC Standard. This is mainly because a utility does not have the rights to remove private trees and the process to acquire rights to remove these trees is quite arduous and costly.** | | |
| 38 | Orange and Rockland Utilities, Inc. | Draft 4 version of R1/R2 | Orange and Rockland Utilities, Inc prefers the Draft 4 version. The wording in the VSLs should be modified for both Requirements to include the phrase 'manage vegetation.' The phrase 'manage vegetation' requires a utility to take specific action to prevent encroachments/outages. |
| | **Response: The SDT thanks you for your comments. The SDT has considered your excellent suggestion about the VSLs and decided to change the Requirements in the manner you describe.** | | |
| 39 | Tampa Electric Company | Draft 4 version of R1/R2 | Quite frankly, the alternatives listed above, or for that matter any other vegetation managment options, should be establised by the utility. The goals in R1 & R2 are very clear. The alternatives listed above will create a double or triple standard of vegetation clearance for each different type of Transmission construction. |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | **Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the confusion you mentioned.** | | |
| 40 | Dominion | Draft 4 version of R1/R2 | The alternate language proposed above suggests that methodologies typically incorporated into processes, procedures, or specifications (as required by R3) should also be included into performance-based requirements R1 and R2. The incorporation of this language into R1 and R2 would change these requirements from performance-based requirements to hybrid performance/competency-based requirements.The intent of R1 and R2 is to define a failure to prevent encroachment into the MVCD. Ensuring that a TO's processes, procedures, or specifications demonstrate adequate means of protecting conductors falls under R3, which incorporates transmission conductor and vegetation dynamics and interrelationships. Therefore, methodologies employed to manage the floor of active transmission ROW should be incorporated into the documentation required by R3 and proof that vegetation was managed in accordance with processes, procedures, or specifications to prevent encroachment into the MVCD will be demonstrated by compliance with R1 and R2. |
| | **Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because it was less prescriptive and more performance-based as you mentioned.** | | |
| 41 | FPL Corporate Compliance | Draft 4 version of R1/R2 | The alternative is a fill in the blanks requirement. |
| | **Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the Alternate language confusing and, as you cite, potentially to be fill-in-the-blanks.** | | |
| 42 | BC Hydro | Draft 4 version of R1/R2 | The alternatives above are too prescriptive. A utility should set a preferred maintenance distance (i.e. clearance 1 in FAC-003-1) as routine expectation and outline mitigation strategies as required in areas where clearance 1 distances cannot be met to ensure that MVCD distances are not encroached upon. Given the various line design |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | | | standards, it is the utility that must define those clearances and margins of error based on engineering standards and the types of vegetation and growth rates present in their operating area. |
| | **Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because it was less prescriptive as you cited.** | | |
| 43 | Western Area Power Administration | Draft 4 version of R1/R2 | The current language of Draft 4 is the most flexible and offers industry the best opportunity for executing a cost effective and efficient program. |
| | **Response: The SDT thanks you for your comments. The SDT has struggled with wording to try to allow each Transmission Owner the flexibility necessary to minimize the risk of vegetation outages while adapting to their unique vegetation challenges in a cost-effective-to-consumers manner. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, because the SDT believes it achieves the goal you cited.** | | |
| 44 | The United Illuminating Company | Draft 4 version of R1/R2 | UI prefers the draft language because we believe the intent of R1/R2 is to capture the actual occurrence of a vegetation related interruption or encroachment of vegetaion into the MVCD based on actual conditions. |
| | **Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft. As you describe, this language captures the true intent of the Requirements in the least confusing and prescriptive manner, as confirmed by other comments received.** | | |
| 45 | Southern Company Transmission | Draft 4 version of R1/R2 | We feel the alternative language is too confusing. Does a utility choose one option from the list and expect it to cover all situations, or can the utility pick one option from the list and apply that option to one span, and then another option for the next span. The proposed alternate verbiage makes no distinction as to when options can or cannot be utilized. The language in Draft 4 seems to cover the various scenarios a utility will face in its vegetation management program while giving the utility the flexibility necessary to address these situations in an appropriate manner. |
| | **Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has** | | |

| | Organization | Yes or No | Question 6 Comment |
|---|---|---|---|
| | **opted to retain the language in the current draft, in part because of the confusion you cited.** | | |

**7. The drafting team and NERC staff disagree on an appropriate set of VSLs for Requirements R1 and R2 and the Standards Committee has directed that both sets of VSLs be posted for stakeholder comments. Which set of proposed VSLs best supports NERC's VSL Criteria?**

**Summary Consideration:**

**Of 45 respondents, 6 chose neither set of VSLs, 8 disagreed with the SDT, and 31 agreed with the SDT.**

**Among those who disagreed with the SDT the major comment issues raised are:**

1. **VSLs are too low and they do not seem to differentiate between various levels of compliance. Commenter is concerned that the difference between an encroachment that leads to an outage and one that does not is based on nothing but luck.**
2. **The NERC staff set requires a higher degree of accountability.**

**The VM SDT considerations for the major comment issues are:**

1. **The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as narrow.**

   **The comment that SDT VSLs are "too low" lacks context. The commenter does not offer a frame of reference in rendering its opinion of "too low".**

   **The comment about luck is without basis. The SDT asserts that vegetation related outages are directly related to the encroachment mechanism, i.e., how vegetation contacts conductors.**

   **The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.**
2. **The VM SDT believes the VSLs are precisely set to reflect the degree of accountability that best matches the level of non-compliance. Grow-in's are classified in the highest level of violation severity precisely because it is indicative of the lowest quality of performance and therefore the entity must be held to the highest degree of accountability in that case.**

**Some minor comment issues are:**

1. **Criteria will be probably best represented by a mix of the two VSLs.**

**2. Neither set is correct.**

**The VM SDT considerations for the minor comment issues are:**

1. **The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable through a hybrid approach as you suggested.**
2. **The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.**

| | Organization | Yes or No | Question 7 Comment |
|---|---|---|---|
| 1 | MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA) | | |
| 2 | Progress Energy | | |
| 3 | Western Electricity Coordinating Council | | |
| 4 | GDS Associates | | Criteria will be probably best represented by a mix of the two VSLs as follows:- Keep the Lower and Moderate VSLs from SDT with both absent Sustained Outage. Add the fall-in as specific encroachment to the Lower VSL and grow-in as specific encroachment to the Moderate VSL- Keep the High / Severe VSLs from NERC |
| | **Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The** | | |

| | Organization | Yes or No | Question 7 Comment |
|---|---|---|---|
| | **differing perspectives do not appear to be reconcilable through a hybrid approach as you suggested.** | | |
| 5 | Pepco Holdings, Inc - Affiliates | | Neither set is correct. The SDT proposed VSLs do not identify encroachment into the MVCD of a line not in an IROL or Major WECC transfer path, and the NERC Staff proposed VSLs do not do not identify encroachment into the MVCD of a line that is in an IROL or Major WECC transfer path |
| | **Response: Thank you for your comment. Measures M1 & M2 along with The Rationale boxes for R1 & R2 can be used to understand what is meant by the MVCD. The Rational Box States:**<br>**"The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method."** | | |
| 6 | CenterPoint Energy | | Neither. However, we recommend that High or Severe violations be based only on Sustained Outages experienced and the reliability importance of the transmission line. Any process or procedure based requirement, if kept within the Standard, should have a Lower or Moderate designation based on the utilities intent or capability to comply with the Requirement. |
| | **Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. Your suggestion is appreciated, however the VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 7 | Consumers Energy Company | VSLs proposed by NERC staff | |
| 8 | Idaho Power Company | VSLs proposed by NERC staff | |
| 9 | FPL Corporate Compliance | VSLs proposed by NERC staff | Again the drafting team is trying to control the terms of a requirement by using the compliance elements. FPL agrees there is a direct link between vegetation growing in to conductors from below has a direct correlation to cascading events and fall-in and blow-in outages are no |

| | Organization | Yes or No | Question 7 Comment |
|---|---|---|---|
| | | | more incidental than a cross arm failure to a cascading event. These components should be handled in the requirements and not in the compliance element. |
| | **Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 10 | Dominion | VSLs proposed by NERC staff | As all parts of R1/R2 seem to contribute equally to the intent of the requirement - shall manage vegetation to prevent encroachment that could result in a Sustained Outage - NERC's proposed VSLs best address noncompliance with the requirements. |
| | **Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 11 | NERC Staff | VSLs proposed by NERC staff | NERC staff supports the VSLs proposed by NERC staff. The SDT's VSLs are too low, and they do not seem to differentiate between various levels of compliance. Still, staff is concerned that the difference between an encroachment that leads to an outage and one that does not is based on nothing but luck. |
| | **Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow.**<br>**The comment that SDT VSLs are "too low" lacks context. The commenter does not offer a frame of reference in rendering its opinion of "too low".**<br>**The comment about luck is without basis. The MVCD distances are conservative and it is quite possible to be well within the MVCD and not have a flashover or an outage. This is based on physics, not "luck". Prudent inspection frequencies and a good imminent threat notification process are 2 things that could prevent encroachments from becoming an outage. Stating that it is only dependent on luck does not give proper credit to prudent operations.**<br>**The SDT has revised R1 and R2 to clarify that the level of maintenance is the primary focus of this requirement that must be attained to be compliant. The VM SDT feels these changes will ensure congruence between the requirements** | | |

| | Organization | Yes or No | Question 7 Comment |
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| | **and the VSL.** | | |
| 12 | Arizona Public Service Company | VSLs proposed by NERC staff | Requires a higher degree of accountability as it should be. |
| | **Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The VM SDT believes the VSLs are precisely set to reflect the degree of accountability that best matches the level of non-compliance. A grow-in is classified in the highest level of violation severity precisely because it is indicative of the lowest quality of performance. Therefore, the entity must be held to the highest degree of accountability for any maintenance failure that leads to a grow-in. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 13 | Idaho Power | VSLs proposed by NERC staff | Seems like there should be a lesser severity level for violations for R3-R7. |
| | **Response: Thank you for your comment. This question asks for feedback on the VSLs assigned to R1 and R2.** | | |
| 14 | The United Illuminating Company | VSLs proposed by NERC staff | United Illuminating agrees with NERC Staff that the Requirement is to prevent encroachment of any kind. Differentiating between fall-in and grow-in is of no consequence to the intent of the requirement. |
| | **Response: Thank you for your comment. Please refer to the SDT response to NERC on this question.** | | |
| 15 | Allegheny Power | VSLs proposed by the VM SDT | |
| 16 | Ameren | VSLs proposed by the VM SDT | |
| 17 | BGE Forestry Management | VSLs proposed by the VM SDT | |
| 18 | Bonneville Power Administration | VSLs proposed by the VM SDT | |
| 19 | Duke Energy | VSLs proposed by the VM SDT | |

| | Organization | Yes or No | Question 7 Comment |
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| 20 | Exelon | VSLs proposed by the VM SDT | |
| 21 | ITC Transmission | VSLs proposed by the VM SDT | |
| 22 | Manitoba Hydro | VSLs proposed by the VM SDT | |
| 23 | MidAmerican Energy | VSLs proposed by the VM SDT | |
| 24 | MRO's NERC Standards Review Subcommittee (nsrs) | VSLs proposed by the VM SDT | |
| 25 | Northeast Utilities | VSLs proposed by the VM SDT | |
| 26 | PPL Electric Utilities | VSLs proposed by the VM SDT | |
| 27 | South Carolina and Gas | VSLs proposed by the VM SDT | |
| 28 | Tri-State Generation & Transmission | VSLs proposed by the VM SDT | |
| 29 | Xcel Energy | VSLs proposed by the VM SDT | |
| 30 | Central Maine Power Company, Iberdrola USA | VSLs proposed by the VM SDT | Agrees with SDT that violation risk factors must be ranked in accordance with impact on the bulk delivery system. |
| | **Response: Thank you for your comment.** | | |

| | Organization | Yes or No | Question 7 Comment |
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| 31 | Kansas City Power & Light | VSLs proposed by the VM SDT | Although the Drafting Team is favored here, it makes little sense in the NERC Staff VSL to have an encroachment with no sustained outage as a HIGH VSL. No compromise of the real-time reliability of the bulk electric system occurred. How could that be a HIGH? If it is determined to use the VSLs proposed by NERC Staff, it is recommended to change the HIGH VSL to LOWER. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 32 | American Transmission Company | VSLs proposed by the VM SDT | ATC believes the VSLs proposed by the VM SDT best supports the NERC's VSL Criteria. The NERC Staff VSLs do not allow for Lower or Moderate VSLs which recognizes significant value as nearly meeting the intent of the requirement. Furthermore, it does not allow for encroachment where absent a sustained outage. Every encroachment in real time would not go directly to a "High" VSL where performance has limited value. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 33 | FirstEnergy | VSLs proposed by the VM SDT | FE supports the VSL proposed by the SDT. We believe these have been developed in accordance with the FERC approved VSL guidelines and represent the appropriate violation levels for situations of varying probabilities. History has proven the grow-ins are the biggest cause of vegetation contact issues, and fall-ins and blowing together vegetation are very hard to predict and control and should be at lower violation levels. Although we believe that an encroachment into the MVCD that causes no system disturbance should not be penalized if an entity takes immediate action to restore the minimum clearance, the assignment of a Lower VSL is appropriate. We believe that the NERC staff opinion that this situation warrants a High VSL does not demonstrate thorough rationalization because it fails to consider the consequences that would place a severe monetary penalty on an entity for a situation that did not cause a fault, outage, or cascade of the BES.Furthermore, it is clear |

| | Organization | Yes or No | Question 7 Comment |
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| | | | from the bullet points under R1 and R2 of the proposed standard language that the SDT intended that an encroachment with a sustained outage is different than and encroachment without a sustained outage otherwise they would not have specified the bulleted situations in detail. Had the SDT intended for there to be only two violation severity levels they would have only specified two bullet items: an encroachment with a sustained outage and an encroachment without a sustained outage. The requirements are the only tools the drafting team has to specify its intent in this area and the approach they used is reasonable to provide these levels of differentiation. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 34 | Great River Energy | VSLs proposed by the VM SDT | GRE prefers the Drafting Team's VSLs over the VSLs written by the NERC staff. The VSLs that were written by the SDT appear to be clearer and less subjective as opposed to the VSLs that were written by NERC staff. The VSLs written by the NERC staff came across as being less clear and more subjective. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 35 | Southern California Edison Company | VSLs proposed by the VM SDT | SCE agrees with the SDT's rationale and proposals for VSL Criteria. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 36 | Tampa Electric Company | VSLs proposed by the VM SDT | Tampa Electric agrees with the SDT statement ... "For example, not all encroachments lead to Sustained Outages." As such, we agree, a lower level of VSL is appropriate. Tampa Electric also agrees with this statement " Moreover, there is an operational differentiation between a fall-in, blow-together or grow-in event. "Recommend the |

| | Organization | Yes or No | Question 7 Comment |
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| | | | team examine the analytical rational for the following statements so as to better explain and clarify this issue to NERC. "A fall-in has never been known to cause a cascading outage. Therefore the team feels that a Lower VSL is appropriate. A blowing-together-caused fault is somewhat more egregious than a fall-in, as it has the potential for re-occurring and is therefore assigned a Higher VSL." |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 37 | PNM | VSLs proposed by the VM SDT | The expectation is for perfection or zero encroachments at all times. It would be cost prohibitive to maintain the system under those rules. PNM recommends the VM SDT VSL's. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 38 | BC Hydro | VSLs proposed by the VM SDT | The NERC staff recommendation is too restrictive and does not seem realistic in an operational sense. We do not agree that the standard should apply to outages from vegetation falling into the conductor from within the active transmission right of way. This normally would not occur except during storm events that would be excluded from this standard. It is operationally difficult to know precisely where the edge of the right of way is in all situations and under all conditions. Further, in clearing some sections to this degree, the utility could end up destabilizing what is currently a stable, windfirm edge and pose higher security risks to the transmission system from destabilizing the vegetation through excessive clearing. So this gets down to semantics of how a utility might define their active right of way corridor relative to the legal statutory right of way edge. The risk of fall into outages needs to be managed but as currently defined this is too absolute a requirement. Fall-into outage risks need to be mitigated but they have not been a key element of any cascading failure and are hard to prevent. Even if a right of way were cleared sufficiently wide to avoid a fall-into outage, there is always a risk of branches being blown into the conductors from sailing during higher winds (e.g. Douglas-fir branches have excellent airborne gliding |

| | Organization | Yes or No | Question 7 Comment |
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| | | | abilities). The greatest risk is from grow-into outages or from conductors and vegetation being blown into one another within the active right of way. Therefore, we prefer the VSLs set by the VM standard development team. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 39 | Consolidated Edison Company of New York Inc | VSLs proposed by the VM SDT | The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line but an encroachement or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 40 | Hydro One | VSLs proposed by the VM SDT | The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line, but an encroachment or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |

| | Organization | Yes or No | Question 7 Comment |
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| 41 | Northeast Power Coordinating Council | VSLs proposed by the VM SDT | The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line, but an encroachment or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 42 | Orange and Rockland Utilities, Inc. | VSLs proposed by the VM SDT | The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line but an encroachement or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 43 | Entergy Services | VSLs proposed by the VM SDT | This gives the option to activate and follow the Imminent Threat Process if a breach of the MVCD is located and reported for isolated events absent a sustained outage. It gives the TO the opportunity to mitigate the issue when it is identified and corrected prior to experiencing an outage.. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |

| | Organization | Yes or No | Question 7 Comment |
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| 44 | Western Area Power Administration | VSLs proposed by the VM SDT | Unlike a “grow-in”, a “fall-in” or “blow-in” has never caused or contributed to a cascading outage. Further, the “zero tolerance” approach of this standard remains impractical and unreasonable. The gradated indicators of program performance associated with a “fall-in”, “blow-in” and “grow-in” offer some measure of reasonableness to the requirement. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |
| 45 | Southern Company Transmission | VSLs proposed by the VM SDT | We support the SDT version of the VSLs. The version proposed by staff does not recognize the objective of FAC-003-2 which clearly states, “To improve the reliability of the electric Transmission system by preventing those outages that could lead to Cascading.” If a fall-in occurs in an afternoon thunder storm and investigation reveals the tree was on the right-of-way by one or two feet, staffs VSLs would treat this outage with the same severity as an outage where a fully loaded line in a heat wave sagged into unmaintained brush growing directly beneath the conductor. The first case would rarely, if ever, lead to cascading. The second case could easily lead to cascading. Staff’s VSLs seem to indicate a desire to “gold plate’ the system to insure 100% reliability, which will never be achieved absent of unlimited resources and with total disregard to cost. |
| | **Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.** | | |

**8. Is there anything that you have not addressed above regarding the draft FAC-003-2 Transmission Vegetation Management standard or the Technical Reference Document? If yes, please provide what you believe should be changed, added or deleted and the rationale for your proposal.**

**Summary Consideration:**

**Of the 45 respondents, 29 provided a comment. In general, there were no common themes and as such each comment was responded to individually. Of some note, two comments were especially lengthy and their well-considered responses are found below.**

| | Organization | Yes or No | Question 8 Comment |
|---|---|---|---|
| 1 | Great River Energy | | |
| 2 | Allegheny Power | No | |
| 3 | Central Maine Power Company, Iberdrola USA | No | |
| 4 | Consumers Energy Company | No | |
| 5 | Duke Energy | No | |
| 6 | Exelon | No | |
| 7 | Manitoba Hydro | No | |
| 8 | Northeast Utilities | No | |
| 9 | Pepco Holdings, Inc - Affiliates | No | |
| 10 | PNM | No | |

| | Organization | Yes or No | Question 8 Comment |
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| 11 | PPL Electric Utilities | No | |
| 12 | South Carolina and Gas | No | |
| 13 | Tri-State Generation & Transmission | No | |
| 14 | Western Area Power Administration | No | |
| 15 | Western Electricity Coordinating Council | No | |
| 16 | Tampa Electric Company | No | No additional comments |
| 17 | GDS Associates | Yes | - Effective Dates. Clarify effective dates in paragraphs 2 and 3. This should only be applicable to Canada as Standard are not mandatory and enforceable in the US unless further approved by FERC.- Exceptions. Regional Differences must be approved just li |
| | **Response: The SDT thanks you for your response. NERC staff will review the effective date section and modify as necessary.** | | |
| 18 | Progress Energy | Yes | 1) On p. 3 of the redline, the table of Effective Dates is struck out, but the key (listed as 1, 2, 3 below the table: “1. First calendar day...”) remains but now the numbers 1, 2, and 3 no longer refer to the table of Effective Dates as the table has been struck. 2) The first paragraph under “Exceptions” could be reworded to be clearer. As currently proposed, it states lines below 200kV become subject to the standard 12 months after the lines are designated as being subject to the standard, which is somewhat circular. We propose instead:”A line operated below 200kV becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as an element of an IROL or as a Major WECC transfer path.”3) |

| | Organization | Yes or No | Question 8 Comment |
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| | | | Applicability Section 4.2.4 says the standard does not apply to Facilities located in the fenced area of a switchyard. However, p. 8 in Section 5 Background says the standard does not apply to underground or submarine lines or line sections inside a station boundary. Two things should be addressed to make these consistent: “Facilities” is a NERC-defined term that includes more than just lines, and includes lines, generators, compensators, transformers, etc. Also, is the “station boundary” always defined by the fenced area? Any potential conflict due to this inconsistency should be resolved.4) In the redline of Draft 4, in R5 and M5, the word “interim” is struck through. However, the Rationale box says “....the intent is for the Transmission Owner to put interim measures in place...” The use of “interim” should be consistent between R5, M5 and the Rationale box.5) R6 requires the TO to perform Vegetation Inspections “at least once per calendar year”. There could potentially be future interpretation requests that question whether “once per calendar year” means performance sometime during each year (i.e. 2010, 2011, etc.), or whether no more than 365 calendar days can elapse between inspections. The first interpretation could allow up to almost 2 years to elapse between inspections even when doing it “once per calendar year”. This should be clarified. |
| | **Response: The SDT thanks you for your response. NERC staff will review the effective date section and modify as necessary. Thank you for the wording, but overall industry consensus does not dictate a verbiage change.**<br><br>**Regarding station boundaries and underground lines, overall industry consensus is that line-based vegetation programs do not apply inside the station boundary. The SDT believes that “fence” is the best overall term for a station boundary.**<br><br>**As to the use of “interim”, the Rationale intends to provide clarifying text and there is no imperative that its language should be identical to the requirement verbiage. The SDT believes that the Rationale language properly conveys the intent.**<br><br>**Regarding the inspection frequency, the SDT added an 18 month clause.** | | |
| 19 | CenterPoint Energy | Yes | 1. CenterPoint Energy believes the proposed FAC-003-2 is not a performance-based standard, despite being labeled as such, because it remains too focused on processes and procedures. CenterPoint Energy fails to see much difference in the approach from the current Standard. |

| | Organization | Yes or No | Question 8 Comment |
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| | | | CenterPoint Energy believes a performance based requirement would provide performance criteria that an entity would be measured against. An example of a performance based requirement would be the following:<br><br>R1. "Each Transmission Owner shall manage vegetation to prevent encroachment that results in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period."<br><br>M1. Each Transmission Owner has evidence that it had in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period. Examples of acceptable forms of evidence may include dated reports of vegetation-related Sustained Outages or dated attestations as to no vegetation-related Sustained Outages have occurred.<br><br>However, if the majority of industry commenters agree with the SDT's approach, CenterPoint Energy has the following additional concerns:<br><br>2. The phrases "active transmission line ROW" and "Active Transmission Line ROW" are no longer considered defined terms and should be deleted from the Standard along with footnote 2, the Compliance Section for Periodic Data Submittal as well as the Guidelines and Technical Basis. As found throughout the Standard, the phrase should be replaced with the common terms utilized in the Guidelines and Technical Basis section, "Transmission Owner's transmission ROW as defined by easement, fee simple, or other legal rights".<br><br>3. In the Background section fall-ins are characterized as "statistically intermittent" and "these types of events are highly unlikely to cause large-scale grid failures". We agree and therefore recommend that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages.<br><br>4. R4 should be deleted. R4 is related to processes and procedures and should be combined into R3. The result of not following the notification process or procedure is that a Sustained Outage may occur that would be |

| | Organization | Yes or No | Question 8 Comment |
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| | | | captured by M1 and M2. The process and procedure would be measured by M3.<br><br>5. R5 and M5 contain the ambiguous phrase, "where a transmission line is put at risk due to the constraint". This phrase should be replaced with the more specific terminology in R1 and R2 as, "where a transmission line cannot perform within its Rating and Rated Electrical Operating Conditions due to the constraint" or as in R3 as "where a transmission line will be subjected to an encroachment into the MVCD due to the constraint".<br><br>6. For R6, the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is "based upon average growth rates across North America and on common utility practice" are unfounded and arbitrary without a specific reference to a North American study.<br><br>7. R7 contains the ambiguous phrase, "provided they do not put the transmission system at risk of a vegetation encroachment". This phrase should be replaced with the more specific terminology in the Rationale for R7 and Requirement R3 as "provided they do not allow encroachment of vegetation into the MVCD."<br><br>8. Just as the force majeure statement was moved to the Applicability section of the Standard, the exception for applicability beyond the Rating and Rated Electrical Operating Conditions should be included in the Applicability section as well. Currently, it is only included in R1, R2, and R3. It should be made clear that the other Requirements and Measurements ARE NOT applicable in situations beyond the Rating and Rated Electrical Operating Conditions. This is already discussed in the Guidelines and Technical Basis but not evident within the Standard.<br><br>9. The Periodic Data Submittal should be clarified to as to the specific conditions under which Sustained Outages are reported. The Applicability section includes the force majeure; however, other exclusions are not so evident. We recommend the wording be changed to include all applicable |

| | Organization | Yes or No | Question 8 Comment |
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| | | | exclusions for added clarity.<br><br>We recommend the following wording: “The Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entity’s designee, identifying the Sustained Outages caused by vegetation, as defined in the categories below, of transmission lines operating within Rating and Rated Operating Conditions as determined by the Transmission Owner, exclusive of the force majeure conditions in Section 4.4, that include, as a minimum, the following.”<br><br>Also, the within the Categories listed, the phrases “active transmission line ROW” should be deleted and replaced with “Transmission Owner’s transmission ROW as defined by easement, fee simple, or other legal rights”. This places the determination of the width of the ROW for determination of fall-in violations clearly on the Transmission Owner and the within the limits of its legal rights to control the vegetation that has fallen into the line under R1 and R2 causing the submittal of a reportable sustained outage.<br><br>10. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context.<br><br>11. We agree that the Rationale test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis.<br><br>12. The Guidelines and Technical Basis should include the background and basis for 4.2.4 that excludes the Standard from applying to fenced substations.<br><br>13. The Guidelines and Technical Basis should contain more specific examples of violations of the Requirements and highlight specific exceptions related to vegetation related outages, especially fall-ins and force majeure exclusions.<br><br>14. The language in R6 refers to inspecting “transmission lines” and Table 1 for |

| | Organization | Yes or No | Question 8 Comment |
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| | | | R6 refers to inspecting "ROW". Both areas should use consistent terminology.<br><br>15. In the Guidelines and Technical Basis section for R6, the reference to the VSL calculation units and the example units should be consistent-the example should use "circuit miles", not just "miles".<br><br>16. In general, the proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas:<br><br>(1) applicability;<br><br>(2) inspection cycles; and<br><br>(3) minimum clearances on National Forest Service lands.<br><br>For instance in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions...." Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard.<br><br>A preferred approach should be to incorporate the following few items into the existing Standard FAC-003-1:<br><br>(1) the RC versus the RRO;<br><br>(2) the designation of a specific inspection frequency;<br><br>(3) the Gallet equation; and |

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| | | | (4) the applicability to National Forest Service lands. |

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| | **Response:**<br>**1) The SDT thanks you for your responses. The standard is intended to be a Results-based standard and includes requirements that are risk-based, competency-based and performance-based. The SDT and NERC staff feels that it represents a significant departure from previous versions. The SDT has considered "per-mile"-based metrics, but believes that FERC will not approve such a metric due to statutory constraints and its stated criteria for approval of a standard.**<br>**2) Based on your comment and others, the SDT has revised the definition of ROW in the NERC Glossary and removed Table 3.**<br>**3) While the SDT agrees that fall-ins are statistically intermittent, the fall-ins from inside the ROW are under the control of the TO and represent an erosion of reliability.**<br>**4) The SDT agrees that there is some logic in your proposal, but the SDT feels that all TOs should have a procedure that results in a defense-in-depth strategy as is in the current draft.**<br>**5) R5 applies in the longer-term Operations Planning time horizon, whereas R1 and R2 apply in real time. On the other hand, R3 is a competency-type of requirement that applies in the Long-Term Planning Time Horizon.**<br>**6) The SDT posed the question of inspection frequency to the overall industry in an earlier posting and received general consensus that a one-year interval would be appropriate but did add an 18 month clause.**<br>**7) R7 addresses shorter-term risks, whereas the language in R3 is about the prevention of encroachments in the wider long-term horizon.**<br>**8) The SDT has considered your suggestion about the applicability section; however, after extensive consideration, the SDT opted not to add the language you suggested since the NERC framework for the Applicability section guides against it.**<br>**9) Thank you. The SDT agrees and hereby adds ". . . except as excluded in Footnote 2" before "that includes." Regarding your suggestion on active TLROW, the SDT changed the definition of ROW in the NERC Glossary.**<br>**10) The issue of combining these documents will be addressed by NERC as the results-based standard-** |

| | Organization | Yes or No | Question 8 Comment |
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| | **making procedural document is finalized.**<br>**11) The final resolution of this issue will be addressed by NERC as the results-based standard-making procedural document is finalized.**<br>**12) The SDT believes that industry generally supports the exclusion of substations from applicability of the standard, and does not believe that every clause or portion of the Standard needs an explanation in the *Guidelines and Technical Basis*.**<br>**13) The team does not feel that extensive examples, especially of violations, have a place in the Standard.**<br>**14) You have pointed out a conflict in nomenclature between two portions of the standard. The team will resolve the conflict.**<br>**15) As mentioned in both M6 and the VSL table for R6, the TO may choose its unit of measure.**<br>**16) The SDT considered the SAR and FERC Order 693 directives together with the imperative that reliability not suffer with the revised standard, and feels that it has improved the Standard accordingly.** | | |
| 20 | Kansas City Power & Light | Yes | 1. Part R4.3, "Enforcement, under Section 4, "Applicability", is confusing as to why it is needed. What is the intended purpose of this part? It is clear that each Requirement, Measure, VRF and VSL when adopted by the NERC BOT and FERC become mandatory and enforceable on the declared effective date(s). There is no need for Part R4.3 to reinforce the compliance enforcement dictated by the established NERC Rules of Procedure.2. Requirement R4: The requirement is clear to notify the appropriate control center regarding conditions that might cause a fault on a transmission facility. The requirement should be clear, this for the Transmission Owners applicable lines and recommend the SDT modify the language in R4 to that end. In addition, there is no action other than notification in regards to this operating condition. Highly recommend the SDT consider adding language to take "immediate actions" to remedy the vegetation condition and remove the threat.3. Requirements R5 & R7 are not clear in that they are for the Transmission Owners applicable lines. This has been a common theme throughout this Standard and by the omission of this language, it is not clear that the intended scope of the requirements do not go beyond the applicable lines. |
| | **Response:** | | |

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| | **1. Thank you for your comment. NERC staff will address this concern.**<br>**2. The SDT feels that the applicability of lines is sufficiently clear in R4. However, it is not appropriate for this Standard to specify any particular action for the TOP to take; this is the realm of TOP-006.**<br>**3. The SDT feels that the applicability of lines is sufficiently clear in R5 and R6.** | | |
| 21 | American Transmission Company | Yes | 1.) Rationale boxes associated with R1, R2 and R3 within the standard include reference Tables and Figures in the “Guidelines and Technical Basis” without specifying where they are located. ATC recommends inserting this information as applicable.2.) ATC raises a previous draft concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. ATC recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements. 3.) ATC believes the Measurements are well written and provide guidance on acceptable compliance evidence related to the requirement.4.) Measurement M2 related to R2 states that outages related to encroachments have records confirming no Real-Time observations of any MVCD encroachments. ATC feels this would be hard to prove as a negative. It could require one to show every single patrol or inspection has documentation stating no real time encroachments were observed.5.) Editorial Comment on Draft SDT VSLs for R2: To clarify the statements made for the Moderate, High and Severe VSLs. please add the verbiage, “into the MVCD” after “The TO had an encroachment.......” |
| | **Response:**<br>**1) The formatting of these Rationale boxes is not set and will be addressed by NERC as the results-based standard-making procedural document is finalized.**<br>**2) This issue will be addressed by NERC as the results-based standard-making procedural document is finalized.** | | |

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| | **3) Thank you for your comments.**<br>**4) As stated in the Measure, an attestation serves as adequate evidence.**<br>**5) Thank you for noticing this oversight. It will be corrected.** | | |
| 22 | MRO's NERC Standards Review Subcommittee (nsrs) | Yes | 1.) The NSRS notices that a previous draft concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. The NSRS recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements. Such as; State within in the text that this information "Is not subject to enforcement". 2.) The NSRS believes the Measurements are well written and provide guidance on acceptable compliance evidence related to the requirement.3.) Measurement M2 related to R2 states that outages related to encroachments have records confirming no Real-Time observations of any MVCD encroachments. The NSRS feels this would be hard to prove as a negative. It could require one to show every single patrol or inspection has documentation stating no real time encroachments were observed.4.) Editorial Comment on Draft SDT VSLs for R2: To clarify the statements made for the Moderate, High and Severe VSLs. please add the verbiage, "into the MVCD" after "The TO had an encroachment......." |
| | **Response:**<br>**1. This issue will be addressed by NERC as the results-based standard-making procedural document is finalized.**<br>**2. Thank you for your comments.**<br>**3. As stated in the Measure, an attestation serves as adequate evidence.**<br>**4. Thank you for noticing this oversight. It will be corrected.** | | |

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| 23 | BGE Forestry Management | Yes | 4.2.4 States that the Standard is not applicable to "...to Facilities .... located inside the fenced area of a switchyard, station or substation". This implies that anything within the fenced area of a switchyard, substation or power plant does not fall within the jurisdiction of FAC-003-2. Some fenced in areas could be very large and susceptible to vegetation encroachments issues. Suggest reference to "inside the fence" be removed.Disagree with R6. - Inspection Frequency. Very prescriptive. Please consider allowing TO's to select an annual frequency that best fits their requirements, such as calendar year, every growing season, every non-growing season, etc. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. BGE believes inspecting during the dormant season is a best practice due to the ability of the inspector to identify vegetation defects, especially off the ROW, which could be hidden during the growing season due to foliage, canopy cover, etc. Also, if a utility elects to leverage an advance technology, such as LiDAR, it provides the most effective results when LiDAR is utilize during the growing season, therefore allowing the results of the advance technology to enhance the fall to spring inspection cycle. Table 1 - Time Horizons, Violation Risk Factors, and Violation Severity Levels The VSL's for R7 all include "the Transmission Owner failed to complete.....% of its annual work plan (including modifications if any)". This is not clear to BGE. R7. allows plans to be modified due to changing conditions, for example ROW maintenance could be deferred to the following year due to mutual assistance agreements if the deferment does not violate the encroachment within the MVCD. The VSL implies this is a violation since the "modification" deferred a certain percentage of the planned worked to the following year, therefore 100% of the planned worked wasn't completed. If the modification was excluded, than 100% of the planned work would have been completed. |
| | **Response:**<br>**1. Regarding station boundaries, overall industry consensus is that line-based vegetation programs do not apply inside the station boundary. The SDT believes that "fence" is the best overall term for a station boundary.**<br>**2. While the SDT lauds BGE's approach, it feels that a calendar year basis affords sufficient flexibility for BGE and other TOs to schedule their inspections.** | | |

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| | **3. The Standard suggests that the TO will begin with an original plan which may then be modified; it is implicit that measurements of plan completion are against the modified plan, not against the original plan.** | | |
| 24 | MidAmerican Energy | Yes | Any references to "observed in real time" should be removed. Vegetation contacts must be verified and references to real time are inappropriate. This causes difficulties in proving a negative in real time. |
| | **Response: The SDT believes that the commenter has misinterpreted the requirement. It is not necessary for the TO to continuously observe; rather, a violation can only be reported if observed in real time.** | | |
| 25 | NERC Staff | Yes | **Effective Dates**<br>• The first item should be re-written to "First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required."<br>• The second item is not needed and should be removed.<br>• The third item is okay but the phrase "where explicit regulatory approval is not required" should be removed.<br>**Exceptions**<br>• Identifying a critical line and then waiting 12 months to perform vegetation management is counter to the risk avoidance strategy that the standard is attempting to accomplish. In effect, this standard permits an entity to identify a major WECC path or an IROL just prior to peak season and then not complete any vegetation management activities until just before the next season 12 months later. This is wholly inappropriate. The Planning Coordinator will identify these lines sufficiently far in advance that the 12-month window will prevent encroachments |

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| | | | • Using the phrase "an element of an IROL" seems confusing because "Element" is a term defined in the glossary. Further, IROL is an identified limit, not a physical component. This should be reworded to say "a facility that is identified to be part of an interface or path impacting an IROL." This is also seen in R1 and R2 and needs to be adjusted there as well. The industry has reviewed this language and has found it to be sufficiently clear.<br>• For newly acquired assets, the 12 month window may be appropriate, but there needs to be a much nearer term inspection undertaken to identify "risky" vegetation.<br><br>**Definition**<br><br>• The modified definition assumes the ROW is maintained, which may not be the case (for instance, if a newly acquired asset has not yet been acted upon). An entity could interpret the new definition to indicate that the new owner cannot be performing an initial vegetation inspection if the ROW has not yet been maintained. The phrase "maintained transmission line" should be changed to "applicable transmission line."<br>• The inclusion of the phrase "which may be combined with a general line inspection" is unnecessary and should be removed. In fact, the current definition does not restrict combining the inspection with other field visits, while in the proposed definition that vegetation inspection can only be combined with a general line inspection.<br><br>**Objectives (Section 3)**<br>• NERC staff is concerned that the purpose states "that could lead to Cascading." This qualifier limits the purpose of the standard, which should be to prevent vegetation-related outages. The more outages there are, the less the overall system reliability; it does not necessarily have to lead to |

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| | | | Cascading to be significant and represent a reasonable risk to the BES.<br>• The term "maintain" might be better than "improve."<br><br>**Applicability (Section 4)**<br>• 4.1 Functional Entities<br>• Noticeably absent from the standard is coverage for transmission facilities that connect generators to the interconnected bulk power system. As such, the team should add Generator Owners to the applicability and include such language that was proposed by the ad hoc team: transmission facilities that connect generators to the bulk power system that exceed two spans from the fence-line of the generating plant; coupled with the previous discussion, this provides complete coverage for all transmission facilities and switchyards and substations. This is what is needed to ensure no gaps in vegetation management coverage.<br>• 4.2 Facilities<br>o The identification of critical facilities herein does not recognize the overarching criteria that are being developed in support of the PRC-023 order, and in some respects, in response to Order 693 directives to define the criteria for "critical facilities." The FAC-003-2 SDT should work in conjunction with the PRC-023 team, which is establishing a set of criteria for identifying critical facilities such that the outcome across all NERC standards is consistent.<br>• "Transmission line" should be capitalized as a NERC-defined term.<br>o 4.2.4: This exclusion seems strange. It would appear that there are no expectations for vegetation management in switchyards, which is unacceptable. We should be able to develop language that requires that a Transmission Owner or Generator Owner maintain vegetation within fenced areas of the |

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| | | | switchyard, station, or substation to the same clearances as one does for the ROWs, without necessarily obligating them to an annual cycle of inspection or management.<br>o<br><br>**Requirement R4**<br>• “Qualified personnel" should be defined. In the Rationale, some examples are listed, but who else counts as “qualified field personnel”? This was intended to be an incomplete partial list.<br>• “At any moment” is an unnecessary qualifier and should be removed (same for M4).<br>• With respect to the phrase “intentional time delay,” intent is a tricky thing to prove. Most standards set clear timelines which kick in regardless of intent, because it diminishes reliability to base a standard on intent. The SDT should consider doing so here.<br><br>**Requirement R5**<br>• NERC staff is confused by the overall purpose of this requirement. It appears to be a defense to a possible violation for failure to perform some planned vegetation work, but it flips it around and makes it a requirement. A better approach would be to just deal with this in addressing the mitigating/aggravating factors under a violation of R1 and R2. This concept is already part (R1.4) of the existing in-force FERC-approved FAC-003-1, but has been renamed to avoid conflict with terminology in the current NERC compliance guidelines.<br>• The team should be more specific with respect to expectations for “corrective action.” There needs to be an expectation that the corrective action needs to maintain an equivalent level of performance consistent with the intent of the vegetation management program. This could include, for example re- |

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| | | | rating lines to reduce max sag until the condition is rectified, enhanced inspection cycles to monitor conditions, etc. It would be useful to define a metric for the success of corrective actions.<br>• The team should be clearer on what constitutes a "constraint." Is it only legal constraints? One interpretation could be resource constraints, which would certainly not be appropriate in this context. The phrase "due to constraints" is also used in the Rationale section. In this context, "constraint" appears to mean congestion on a transmission line. This seems very different from being "constrained from performing planned vegetation work." In fact, the existence of congestion on a line does not necessarily create risk. We would not want entities to make the economic determination that they will put off required vegetation work because it would cost too much in energy sales profits.<br><br>**Requirement R6**<br>• It would appear necessary to require the use of the inspection information to guide or modify program development as is identified in the Rationale box accompanying the requirement. This is referred to in R7 but is not identified as an expectation from R6.<br>• What are "all applicable transmission lines"? Are those lines covered by both R1 and R2? Clarify this.<br>• "Once per calendar year" requires more guidance. Would two inspections on 12/31/2010 and 1/1/2011 satisfy this requirement? Shouldn't there be a requirement to space these inspections out? Recommend: once per calendar year with no more than 15 months between inspections.<br>• The last sentence of R6's Rationale states that "Transmission Owners should consider local and environmental factors that could warrant more frequent inspection." But the way the |

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| | | | requirement is written, there is no basis for requiring anything more frequent than once per calendar year. If the intent is to have stricter timelines for different registered entities, then the standard would need to be revised.<br><br>**Compliance**<br>• Additional Compliance Information<br>o Categories of Sustained Outages<br>▪ Category 3 (Fall-ins from outside the ROW) should be reinstated. Even if it is not required by the standards, Category 3 reporting should be kept. The SDT believes that the current NERC TADS process captures such information adequately.<br>▪ There is currently a public bulletin to encourage Transmission Owners to report Category 1 and 2 outages within 48 hours. The SDT should consider adding this as a requirement and including it in the new standard as such. The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient.<br><br>**VSLs**<br>• The VSL for R3 should be shifted to an approach that simply counts the missing elements: Thanks for your comments. The SDT has modified the VSLs for R3.<br>o lower = missing one element<br>o moderate = missing two elements<br>o high= missing three elements<br>o severe = not having documents<br>• The VSL for R4 uses the phrase “vegetation threat,” which needs to either be conformed to the text of the drafting team or defined. This VSL also uses the phrase “intentional delay” A |

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| | | | truly intentional delay should be labeled as severe, not just high. (And as already stated, intent is a very tricky thing to prove.) In the context of the requirement, Measure and VSL, the term “vegetation threat” is self-evident. Refer to the SDT’s earlier reply regariding “intentional delay”.<br>• For the VSL for R5, there may be ways to differentiate violations based on whether the entity identified appropriate corrective actions (versus missing obvious alternatives), attempted corrective actions but failed, considered alternative corrective action, etc. The SDT has considered this but has not identified a good means of differentiation. Additionally, industry stakeholders have not offered any means of differentiation. The SDT would welcome a proposal.<br>• For the VSL for R6, the SDT should differentiate between the criticality of different lines. At the very least, a failure to inspect R1 lines should be a more severe violation than a failure to inspect R2 lines. The risk to the system is properly addressed by the VRFs, not by the VSLs.<br>• The VSL for R7 should perhaps be differentiated based on whether the incomplete work related to critical versus non-critical or less critical lines (i.e., R1 lines vs. R2 lines). The risk to the system is properly addressed by the VRFs, not by the VSLs.<br><br>**Guidelines and Technical Basis**<br>• R1/R2<br>o “If an investigation of a fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation”: This is an important statement and should be included as part of the requirement itself. The SDT feels that this is really more of a “Measure” issue than a “Requirement” issue, and is adequately captured in M1.<br>• R3 |

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| | | | o With respect to the phrase "an adequate transmission vegetation management program," the standard talks about factors to consider, but the requirement does not include any provisions on which to base a determination of adequacy. NERC staff believes it should. With NERC's movement to the results-based standard-making techniques, this is an outstanding issue that can best be resolved once RBS techniques are firmly established.<br>o The guideline states, "This approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation," but nothing in the requirements actually provide explicitly for such evaluations. The SDT asserts that with the totality of R3, M3 and associated VSLs, it is possible for the auditor to assess the TO's intent, competency, etc.<br>• R4<br>o "Cellular service or two-way radio disabled" should not be considered an acceptable unintentional delay. This seems to be within the entity's control: there may be a difference between whether the cell service problems are due to network problems as opposed to the entity failing to charge the phone or pay the bill. The SDT has considered the comments, but believes the verbiage is adequate.<br>o "Remote field locations" should not be considered an acceptable unintentional delay. This is not entirely beyond the registered entity's control. There may be a difference between a work site that is isolated from radio or cellular networks versus the fact that the employee simply left the radio in the truck. The SDT has considered the comments, but believes the verbiage is adequate.<br>o "Vegetation-related conditions that warrant a response" should be defined in the standard. Qualified personnel |

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| | | | are ab;le to assess the conditions as called for in the Requirement.<br>o It is not clear to NERC staff that a lineman or an arborist is capable of completing “an assessment of the possible sag or movement of the conductor” out in the field in real time. However, if this is the expectation, it should be written into the requirements. The SDT believes it is necessary to rely on field personnel for routine decisions in the field, and that it is impractical and unworkable for engineering or survey teams to examine every questionable site. The SDT has considered the comments, but believes the verbiage is adequate.<br>o The fourth paragraph states that the “Transmission Owner has the responsibility to ensure the proper communication…” Earlier in this section, however, it says that the condition of the communication system is not considered to be intentional delay. This inconsistency needs to be addressed. This sentence should also include a requirement for correcting the vegetation encroachment. The SDT agrees with your observation and will clarify the wording to indicate communication “processes” between field personnel and control centers are the issue being addressed.<br>o The phrase “minutes or hours” is used in the final sentence of the fourth paragraph of this sentence. This detail should be written more clearly and written into the standards. Is 24 hours still hours? What about 48 hours? The SDT has conceived of cases where a 10-hour or more delay may be perfectly acceptable, but others where a 10- or 20-minute delay is inexcusable. The SDT believes that no rigid timeline is appropriate.<br>• R6<br>o With respect to the following sentence, beginning with “Therefore it is expected,” NERC staff is concerned that |

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| | | | nothing in the requirement actually makes this expectation enforceable. It would be best to require each TO that experiences a vegetation related sustained outage to investigate the outage and make revisions to its TVMP if the investigation shows that the growth rates of vegetation under the TO's control do not match those anticipated in the TVMP. The primary definition of "expected" is "looking forward to a probably occurrence", not a "required activity," and so the SDT believes that the verbiage is appropriate.<br>• R7<br>o The second paragraph states that "recent line inspections may identify unanticipated high priority work." But the fifth bullet in R7 does not indicate that the higher priority work was identified in a recent line inspection. R7 should be revised to make that caveat clear. The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in identifying unanticipated high-priority work.<br>o The second paragraph references "Modifications to the annual work plan." Presumably, these modifications would not excuse compliance with R1, R2, and R6. That should be made clearer in the requirements. Thank you for the comments.<br><br>**Table 3**<br>• None of the requirements actually reference this table. That should be modified. Thank you. The Table will be removed.<br>• |
| | **Response:** | | |

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| | **Effective Dates**<br><br>**The SDT assumes that NERC staff will correct implementation timetable conflicts.**<br><br>**Exceptions**<br><br>**The SDT considered such language, but ultimately determined that it was unnecessary, partly because the response to “hot-spot”-type conditions is not part of this standard.**<br><br>**Definition**<br><br>• **Thank you for your excellent comments. The SDT has made changes to meet this concern.**<br>• **Previous overwhelming industry comments have dictated the need for the SDT to clarify this language as it exists in the current draft. The current definition offers no restrictions that the vegetation restriction may only be combined with a general line inspection.**<br>**Objectives (Section 3)**<br>• **The Purpose as currently stated reflects broad industry consensus that earlier Purpose statements were over-reaching.**<br>• **The Purpose as currently stated reflects broad industry consensus.**<br><br>**Applicability (Section 4)**<br>• **Re: generators - There is a NERC GO/TO team established to address this issue.**<br>• **Re: critical facilities - While the SDT is aware of the interest in FERC to consolidate tests or criteria for so-called “critical” facilities, NERC leadership have indicated to FERC staff its commitment to separate efforts for use by PRC-023 and this standard.**<br>• **Re: capitalizing Transmission Line - The SDT agrees and thanks you for your comments.**<br>• **Re: 4.2.4 - Wide industry consensus is that line-based vegetation programs should not apply inside the station boundary. Also, as previously mentioned, another NERC team is examining the TO/GO issue.**<br><br>**Requirement R4**<br>• **Re: qualified personnel - The SDT changed the language to confirmation by the Transmission Operator.**<br>• **Re: “At any moment” - The SDT believes that “at any moment” is a necessary but sufficient qualifier.**<br>• **Re: “intentional time delay,” - The SDT has considered this. FERC has already approved other standards with the same language.** | | |

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| | | | **Requirement R5**<br>• **Re: corrective action - Past and recent industry comments indicate little confusion on this portion of the Standard.**<br>• **Re: constraints - Past and recent industry comments indicate little confusion on this portion of the Standard.**<br><br>**Requirement R6**<br>• **Re: inspection information - The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in developing its annual plan.**<br>• **Re: "all applicable transmission lines" - Please refer to section 4 ("Applicability") of the draft.**<br>• **Re: calendar year - The SDT posed the question of inspection frequency to the overall industry in an earlier posting and received general consensus that a one-year interval would be appropriate.**<br>• **Re: Rationale - The SDT does not intend that stricter timelines be rigidly defined or employed.**<br><br>**Compliance**<br>• **Re: Category 3 (Fall-ins from outside the ROW) - The SDT added this back in.**<br>• **Re: Public bulletin - The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient.**<br><br>**VSLs**<br>• **Re: VSL for R3 - The SDT has modified the VSLs for R3.**<br>• **Re: VSL for R4 - In the context of the requirement, Measure and VSL, the term "vegetation threat" is self-evident. Refer to the SDT's earlier reply regarding "intentional delay".**<br>• **Re: VSL for R5 - The SDT has considered this but has not identified a good means of differentiation. Additionally, industry stakeholders have not offered any means of differentiation. The SDT would welcome a proposal.**<br>• **Re: VSL for R6 - The risk to the system is properly addressed by the VRFs, not by the VSLs.**<br>• **Re: VSL for R7 - The risk to the system is properly addressed by the VRFs, not by the VSLs.**<br><br>**Guidelines and Technical Basis**<br>• **Re: R1/R2 - The SDT feels that this is really more of a "Measure" issue than a "Requirement" issue, and is adequately captured in M1.**<br>• **Re: R3 –**<br>  o **With NERC's movement to the results-based standard-making techniques, this is an outstanding** |

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| | issue that can best be resolved once RBS techniques are firmly established.<br>o The SDT asserts that with the totality of R3, M3 and associated VSLs, it is possible for the auditor to assess the TO's intent, competency, etc.<br>• Re: R4 -<br>o Re: "Cellular service or two-way radio disabled" - The SDT has considered the comments, but believes the verbiage is adequate.<br>o Re: "Remote field locations" - The SDT has considered the comments, but believes the verbiage is adequate.<br>o Re: "Vegetation-related conditions that warrant a response" - Qualified personnel are able to assess the conditions as called for in the Requirement.<br>o Re: "assessment of the possible sag or movement of the conductor" out in the field - The SDT believes it is necessary to rely on field personnel for routine decisions in the field, and that it is impractical and unworkable for engineering or survey teams to examine every questionable site. The SDT has considered the comments, but believes the verbiage is adequate.<br>o Re: The fourth paragraph - The SDT agrees with your observation and will clarify the wording to indicate communication "processes" between field personnel and control centers are the issue being addressed.<br>o Re: The phrase "minutes or hours" - The SDT has conceived of cases where a 10-hour or more delay may be perfectly acceptable, but others where a 10- or 20-minute delay is inexcusable. The SDT believes that no rigid timeline is appropriate.<br>• Re: R6 -<br>o Re: sentence beginning with "Therefore it is expected," - The primary definition of "expected" is "looking forward to a probable occurrence", not a "required activity," and so the SDT believes that the verbiage is appropriate.<br>• Re: R7 -<br>o Re: The second paragraph - The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in identifying unanticipated high-priority work.<br>o Re: The second paragraph references "Modifications to the annual work plan." - Thank you for the comments.<br><br>Table 3<br>• Thank you. Table 3 has been removed. | | |
| 26 | FirstEnergy | Yes | FE has the following additional comments:1. In the SDT consideration of |

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| | | | comments from Draft 3, it was indicated that "The subcommittee will ask that NERC's legal department write a statement for addition to each standard to clarify which parts/elements of the standard are mandatory and enforceable and which are provided only as information". We would appreciate this statement be placed into the standard before the final ballot so stakeholders have an opportunity to review and comment on the wording.2. We cannot comment on the Technical Reference Document since the latest draft was not posted for review. Does NERC intend to post this at a later time? If so, we ask that NERC give the industry enough time to adequately review the document so that we can provide quality feedback.3. In the Guidelines and Technical Basis Section, in the first paragraph of Requirement R5, second sentence, the word "temporarily" should be removed since it was removed from the requirement. |
| | **Response:**<br>**The SDT thanks you for your comments.**<br>**1) The NERC legal department has been contacted to provide a statement to clarify which parts/elements of a standard are mandatory and enforceable and which are provided only as information. This statement is nearing finalization and when completed will be posted as a separate document when the next draft of FAC-003-2 is posted.**<br>**2) The Technical Reference Document is not a mandatory and enforceable document but your feedback is definitely appreciated once the document is finalized. The Technical Reference will be updated during the next ballot which will start during early August. The SDT will finalize the Technical Reference document at the August meeting in Toronto, ON which is scheduled from 8/17-8/19/10 and will post for comment.**<br>**The word 'temporarily' has been removed from the Guidelines and Technical Basis as requested. Thank you for your comment.** | | |
| 27 | Ameren | Yes | Funding Adjustments (increase or decrease) - need more description to imply only when planned vegetation work is "over and above". |
| | **Response: Thank you for your comment. The SDT believes your observation and question is the same as voiced in Question 5. As stated in the SDT's response to Ameren's Question 5, we reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the** | | |

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| | **MVCD.** | | |
| 28 | Hydro One | Yes | Hydro One wants to thank the SDT for the effort that has gone into developing this proposed revision to FAC-003. Overall the new version is consistent with FERC Order 693 and will be a straightforward, workable, and auditable standard. One item requiring clarification and change is the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable. In many areas design standards allow a smaller ROW width with no compromise to "cleared width" or tree related reliability of the line. The SDT needs to address this issue. In R5, the phrase 'where a transmission line is put at potential risk due to the constraint' should be better defined. This is vague and could lead to inconsistent practices between utilities. All undesirable species on the full width of the ROW are defined as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification. |
| | **Response: The SDT thanks you for your response. Your objection to our attempt to define a minimum width of the Active Transmission Right of Way was very similar to many other commenters. The SDT has subsequently revised the definition of ROW.**<br>**The issue you mention with R5 and "potential risk to the system" is understandable. The SDT changed this.** | | |
| 29 | Idaho Power Company | Yes | I would like to see something more from NERC to clear the way for utilities to do vegetation management on federal lands that will allow timely vegetation management without delays from these federal entities. |
| | **Response:**<br>**Thank you for your comments. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner. There is joint UAA/EEI Task Force that is working on an MOU with the Federal Agencies to address these issues which are outside the purview of NERC Reliability Standards.** | | |
| 30 | Idaho Power | Yes | I'd like to see language or NERC support to encourage federal agencies to expedite vegetation management maintenance requests and minimize the |

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| | | | barriers to perform work on federal lands. |
| | **Response:**<br>**Thank you for your comments. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner. There is joint UAA/EEI Task Force that is working on an MOU with the Federal Agencies to address these issues which are outside the purview of NERC Reliability Standards.** | | |
| 31 | Dominion | Yes | In R4 and M4, the phrase "without any intentional time delay" has been added. We recommend removing this language from the requirement as it is not possible to measure intent. |
| | **Response:**<br>**Thank you for your comment. Please refer to the SDT response to NERC staff above regarding R4.** | | |
| 32 | Consolidated Edison Company of New York Inc | Yes | In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Con Edison defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification. |
| | **Response:**<br>**The SDT thanks you for your comments. As described in the Technical Reference document (See Page 30), R5 is not intended to address situations where the transmission line is not at potential risk, meaning risk of a Sustained Outage, and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action. However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line.** | | |

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| 33 | Orange and Rockland Utilities, Inc. | Yes | In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Orange and Rockland Utilities, Inc. defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification. |
| | **Response: The SDT thanks you for your comments. As described in the Technical Reference document (See Page 30), R5 is not intended to address situations where the transmission line is not at potential risk, meaning risk of a Sustained Outage, and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action. However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line.** | | |
| 34 | Entergy Services | Yes | ITEMS of concern listed below:ITEM 1: Page 13 of the Standard Draft 4 under Add'l Compliance Information - Periodic Data Submittal......Clarify if Immediate Reporting is expected for outages in Outage Categories 1A, 1B, 2, or 4........or if Quarterly Reporting is all that is expected. It does not specifically say that IMMEDIATE Reporting is Required for any outage type. It is assumed that IMMEDIATE reporting is required for some outages, but is unclear.ITEM 2: Agree that text boxes being used for additional clarity is a benefit if used in a correct and clear manner, but it needs to be specifically stated in the document that the text boxes are to be used for reference only, we will not be required to specifically follow the language in the rationale, and that and each utility should specify their own exact process for addressing each Requirement.ITEM 3: Language should be added to the Guideline and Technical Basis Section to clarify or re-state that this section that this section is for assisting entities in understanding how to comply with the standard but does not contain mandatory actions/activities.ITEM 4: Please clarify defining factors that constitute "wind shear or fresh gale" as referenced in Section 4.4 Other. This is a very unclear interpretation and will most likely be interpreted |

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| | | | differently by all involved if not specified. |
| | **Response: Thank you for your comments.**<br><br>**ITEM 1: There is no requirement in this Standard for immediate reporting of any vegetation outage to the TO's RE. The TO's RE may require more frequent reporting or immediate reporting of any vegetation related outage. There may be other standards that apply to any transmission line outage that require immediate notification to the RE, NERC FERC, FBI, DOT and/or DOE. The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient.**<br><br>**ITEM 2: The Rationale boxes are intended to provide clarity and foundation behind each requirement. They are not a part of the requirement and are not sanctionable, as such. You are correct that every TO is required to structure its TVMP to comply with the standard as vegetation conditions exist. The NERC legal department has been contacted to provide a statement to clarify which parts/elements of a standard are mandatory and enforceable and which are provided only as information. This statement is nearing finalization and when completed will be posted as a separate document when the next draft of FAC-003-2 is posted.**<br><br>**ITEM 3: The Guideline and Technical Reference paper Disclaimer on Page 6 of the document clearly states that the supporting document is supplemental to the reliability standard FAC-003-2 – Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.**<br><br>**ITEM 4: Wind Shear and Fresh Gale are defined terms by the National Oceanic Atmospheric Administration (NOAA). Fresh gale is defined as straight line winds of between 39-46 mph. Wind Shear according to NOAA is a complicated formula that no one will ever use. Wind Shear definition according to NOAA Glossary is "The rate at which wind velocity changes from point to point in a given direction (as, vertically). The shear can be speed shear (where speed changes between the two points, but not direction_, direction shear (where direction changes between the two points, but not speed) or a combination of the two.** | | |
| 35 | Northeast Power Coordinating Council | Yes | NPCC wants to thank the SDT for the effort that has gone into developing this proposed revision to FAC-003. Overall the new version is consistent with FERC Order 693 and will be a straightforward, workable, and auditable standard. One item requiring clarification and change is the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable. In many areas design standards allow a smaller |

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| | | | ROW width with no compromise to "cleared width" or tree related reliability of the line. The SDT needs to address this issue. In R5, the phrase 'where a transmission line is put at potential risk due to the constraint' should be better defined. This is vague and could lead to inconsistent practices between utilities. All undesirable species on the full width of the ROW are defined as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification. |
| | **Response: The SDT thanks you for your response. Your objection to our attempt to define a minimum width of the Active Transmission Right of Way was very similar to many other commenters. The SDT has revised the definition of ROW.**<br>**The issue you mention with R5 and "potential risk to the system" is understandable. The SDT amended the language.** | | |
| 36 | Arizona Public Service Company | Yes | Qualifications needs to be put back in the standard. There needs to be a clearance 1 requirement. |
| | **Response: Thank you for your comments. Training and qualifications are best addressed in the NERC PER standards. Additionally please refer to the SDT response to question 8, comment 42, regarding the issue of Clearance 1.** | | |
| 37 | Xcel Energy | Yes | R1 & R2 states that "types of encroachments include:" - is the way this is worded intended to imply there can be other types of encroachments that are not listed? If not, then rephrase the leading sentence to be definitive and indicate that the types are the only categories to be considered. We suggest that the wording from the prior draft, i.e., " . . . limited to".MCVD should be a defined term in the glossary, not in a "Rationale" box.R1 "1" should Real-time be capitalized to reflect the glossary definition? The term is used as "real time", "Real time" and "Real Time" throughout the standard. This seems to be just a drafting issue, but the same term should be used consistently. Need to establish somewhere that the entity defines what constitutes a "qualified" person. Further, some portions of the standard use the term "qualified person" (e.g., see M1) and others reference "qualified field personnel" (e.g., see the Rational Box near M3). It seems that all references should be to |

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| | | | "qualified field personnel."R1 & R2 are duplicative. It appears the only reason for the separation is so that different VRFs can be assigned. Why not just have 1 requirement and indicate that the VRF is High for one set of lines and Med for others?In general, the "Rationale" boxes force the requirement language into a difficult to read format.R5/M5 - the measures identified do not constitute "corrective actions", they merely identify documentation that work was attempted. Corrective actions should be "actions", such as establish an increased monitoring plan, re-rating of the line, removal from service, etc.R6 - Xcel Energy still believes the requirement in R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were "one size fits all". If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R6 be revised to read as follows: Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.The Effective Dates section is confusing - exactly when would this standard be in effect? It lists 3 approvals...do all three have to be met or just one?The reference to Major WECC transfer paths in the requirements introduces a weak element. The WECC major path designation and elements that comprise those paths should be controlled through a robust process and easily available to WECC members. Currently, there are some concerns around that process in general.NERC's concerns regarding reporting vegetation related outages within 48 hours |

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| | | | should be addressed or clarified in the Compliance section. (i.e., incorporate or indicate that this supersedes that recommendation). Ref: Public Notice - NERC Compliance Process #2008 - 001 |
| | **Response: Thank you for your comments. The yellow highlighting refers to commenter issues. The SDT response follows.**<br><br>**R1 & R2 states that "types of encroachments include:": To address your concern, there are only (4) types of failure- to- manage types of encroachment as defined in R1 and R2 as it relates to compliance with FAC-003-2. The SDT appreciates your perspective but believes the requirement as written is clear to the point of only four encroachment types.**<br><br>**MCVD should be a defined term in the glossary, not in a "Rationale": This term refers to a Table of values that is clearly defined within the standard itself.**<br><br>**The term is used as "real time", "Real time" and "Real Time" throughout the standard. : Thanks for identifying this inconsistency and the SDT will review and address as appropriate.**<br><br>**Need to establish somewhere that the entity defines what constitutes a "qualified" person.: This was replaced with confirmed by the Transmission Owner.**<br><br>**Further, some portions of the standard use the term "qualified person" (e.g., see M1) and others reference "qualified field personnel" (e.g., see the Rational Box near M3).: Thanks for recognizing this inconsistency. The term "qualified" was replaced with confirmed by the Transmission Owner.**<br><br>**R1 & R2 are duplicative. It appears the only reason for the separation is so that different VRFs can be assigned. Why not just have 1 requirement and indicate that the VRF is High for one set of lines and Med for others?: The SDT is following the VSL and VRF Guidelines which required us to designate two requirements since the VRFs are different for the applicable lines in the two requirements.**<br><br>**R5/M5 - the measures identified do not constitute "corrective actions", they merely identify documentation that work was attempted.: The measures in R5 are evidence that appropriate corrective action was taken by the TO. Trying to identify very specific actions would be prescriptive in nature and difficult to cover a broad spectrum of potential corrective actions.**<br><br>**R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions: As stated in previous comment responses, the SDT was directed by Order 693 to set a minimum inspection criteria and the SDT feels that an annual inspection is a reasonable minimum frequency.**<br><br>**Effective Dates section is confusing - exactly when would this standard be in effect? The SDT has revised the effective date language for clarity. Please refer to change in revised draft.** | | |

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| | **WECC major path designation and elements that comprise those paths should be controlled through a robust process and easily available to WECC members. Currently, there are some concerns around that process in general. : This is an issue that needs to be directed to WECC rather than the SDT.**<br><br>**48 hours should be addressed or clarified in the Compliance section. (i.e., incorporate or indicate that this supersedes that recommendation). Ref: Public Notice - NERC Compliance Process #2008 – 001: This Public Notice is a requirement for a Regional Entity to report to NERC.** | | |
| 38 | BC Hydro | Yes | 1. R4 - There will likely be issues of definition over what constitutes an “intentional delay” in notification. The time for reasonable reporting needs to be quantified.<br>2. The standard references Tables 2 and 3 but there is no Table 1 in the document. This is confusing and should be renumbered. This is likely a carry over from an earlier draft where a Table 1 has been renamed or dropped.<br>3. As noted earlier in Q1, table 3 is poorly developed and should be revisited.C<br>4. How does one objectively measure compliance to MVCD distances? Use of LiDAR technology, laser rangefinders, etc. should be used and evidence of potential violations should be empirical and not based solely on subjective observations, even if they are performed by “qualified personnel”.<br>5. The technical document should include a glossary of all the acronyms used throughout the document as it has some excessive jargon and does not always read smoothly, especially compared to FAC-003-<br><br>The use of explanation boxes is helpful. |
| | **Response:**<br>**1 The SDT debated a set time limit. The team could not find a time that would fit all situations. Intentional would apply if a TO withheld notification after having confirmed that risk conditions exist.**<br>**2 The standard has been revised**<br>**3 The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of ROW.** | | |

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| | 4 **The determination of a potential violation should employ any technology available**<br>5 **SDT has defined unusual terms not found within the industry.**<br>6 **Thank you** | | |
| 39 | The United Illuminating Company | Yes | R4:In R4 the phrase: without any intentional time delay, is a concern. There is a time line between identification and reporting of an imminent hazard that represents the minimal time required to complete this Requirement. Any situation where the time between observation and reporting is greater than this minimal time line indicates a time delay occurred. It will be left to the compliance enforcement authority to determine if this delay was intentional or not. It is not proper for the test to be based on Intentional versus Non-Intentional. Using other synonyms such as reasonable, expeditious, prompt, immediate or without hesitation all introduce a qualitative not a quantitative attribute to the measurement. The Supplemental Reference for R4 indicates that the imminent threat requirement is measured in minutes or hours; again no guidance for enforcement. R4 would be improved with an explicit time requirement of 6 hours between observation and report. This is measurable and clear.R4 should be: Each Transmission Owner shall notify the control center holding switching authority for the associated transmission line no more than 6 hours of a qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment.Other commenter's will argue that 6 hours is arbitrary or unduly prescriptive. I believe it is in line with the Supplemental Reference and adds clarity to the enforcement process.M4 becomes Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel, will have evidence that it notified the control center holding switching authority for the associated transmission line within 6 hours of observation.The Transmission Owner can use the inspection as evidence of the time of observation.Effective Dates: The effective dates in the implementation Plan is in a different form then UI was expecting. Effective Date 1 UI has no comment.Effective date number 2 implies that if the BOT approves the standard and FERC takes no action (neither approves, remands or withholds approval of the standard) then the standard will become effective in one year. This seems to create the possibility of an effective standard without enforceability.Effective Date number 3 implies that regardless of any action by FERC the standard will become effective at least |

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| | | | one year following BOT approval. Again this creates an effective standard without enforceability. Also the use of “at least one year” does not add any clarity to when the Standard would be effective any way. |
| | **Response:**<br>**Thank you for your comments. The SDT considered a fixed time as you offer. We rejected that alternative as the situations under which conditions are found that can cause a Fault at any moment vary widely based on the terrain, weather and available transportation and communication methods. This Requirement is directing the TO to communicate the condition as soon as the above mentioned constraints will allow.**<br>**We have addressed your concerns by revising the effective date language.** | | |
| 40 | FPL Corporate Compliance | Yes | R5 as written is vague. It leads to confusion in interpretation. FPL recommends the following wording.R5. The Transmission Owner shall certify each corridor or line section that it meets the standards it set forth under R3 until the next planned management cycle when it is completed. If a location in known to not meet the criteria defined under R3, a mitigation plan must be in place to prevent a violation of R1 or R2.R1 and R2 are too inclusive. They equate vegetation growing in to conductors from below the same as vegetation falling or blowing into the conductors from within the Active ROW. There is no evidence that a cascading event has ever been caused by the latter two events. This standard should concentrate on vegetation growing from below the conductor. Suggested wording of R1 and R2 is as follows.R1. Each Transmission Owner shall manage vegetation to prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2 from within the active ROW on of any line identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Encroachments are determined by: 1. An encroachment, observed in real time, 4. An encroachment due to a grow-in from below the conductor in the active ROW that caused a Fault.R1. Each Transmission Owner shall manage vegetation to prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2 from within the active ROW on of any line that is not an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Encroachments are determined by: |

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| | | | 1. An encroachment, observed in real time, 4. An encroachment due to a grow-in from below the conductor in the active ROW that caused a Fault. |
| | **Response: The STD recognizes that defining any risk is subjective. Removing the term does not change the fact that each TO must determine the risk and respond accordingly.**<br>**The SDT has placed reference to the different severity of the respective violations into R1 and R2. Both NERC and FERC are on record that fall-in and blow-in interruptions place sufficient risk to the system that they should be part of the standard.** | | |
| 41 | MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA) | Yes | Requirement R4.uses the phrase "notify the control center holding switching authority for the associated transmission line" when a vegetation condition is confirmed which is likely to cause a Fault. Switching jurisdiction may be assigned to a manned substation located closer to a line rather than a remote 24/7 manned control center. However, the switching substation will notify its control center. The control center may need to notify and coordinate with its Balancing Authority or neighboring control centers. Suggest changing the phrase as follows: "notify the appropriate control center(s)for the associated transmission line" |
| | **Response: The SDT thanks you for your comments. The example you provided in your comment is in compliance with the Requirement as written. The local procedure developed by a Transmission Owner may involve multiple notification steps but, as long as the proper operating personnel holding switching authority for that associated line is notified without any intentional delay, the Requirement is met. Due to multiple variations in utility notification procedures across North America, the SDT has decided to retain the existing language in the current draft.** | | |
| 42 | Southern California Edison Company | Yes | SCE questions the need for including the “Guidelines and Technical Basis” section within the body of the standard and is also curious as to the criteria used in developing new Table 3.SCE finds this Draft (4) to be the best work product thus far, and commends the SDT for its efforts and continued dedication to crafting a best-in-class standard. |
| | **Response: The SDT thanks you for your comment. The ‘Guidelines and Technical Basis” is part of the format change with a “results based” standard. The idea is to bring some of the technical reference documentation into the Standard. This will hopefully make the entire Standard a more complete document and will reduce the need to have both the Standard and the Technical Reference Document in hand.** | | |

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| | **Table 3 was an attempt to define a "minimum width" of the Active Transmission Right of Way. This table, along with the footnote, has been removed from the Standard. The definition of Right of Way has been changed in the Glossary.** | | |
| 43 | Bonneville Power Administration | Yes | The basis of managing vegetation to MVCD in Table 2 (essentially withstand distances) will likely prove problematic. BPA believes NERC should develop an additional table that calls out minimum "buffers" based on attributes such as line voltage, line rating etc. This table should be a companion to Table 2. It is NERC's responsibility to regulate and we believe that they should do so. In this case, the loss of flexibility for the owners is not necessarily a bad thing. |
| | **Response: The SDT thanks you for your comments. As described in the Background Section of the Standard, FAC-003-2 is being drafted utilizing a Results Based Standard approach. One component of this type of Standard is that requirements within a standard are not too prescriptive allowing for flexibility. An additional Table would be considered overly prescriptive and in direct conflict with our guidance. It is the Transmission Owner's responsibility to identify the 'buffers' that you mention, not NERC. Since conditions vary significantly across North America, maintaining this specific buffer distance may not be feasible for all utilities.** | | |
| 44 | Southern Company Transmission | Yes | The NERC Glossary of Terms provides a definition for Flashover. The Rationale boxes for R1 and R2 use the term "spark-over". This is inconsistent with other references in the Standard. Note that the term Flashover is used in footnote No.4. Please resolve the inconsistency between these terms.We are concerned FAC-003-2 is being developed under a zero tolerance philosophy, while other NERC standards do not adopt a zero tolerance philosophy. Industry performance under FAC-003-1 indicates the standard is working and that industry is responding to ensure reliability of the electric Transmission system.We would like to thank the SDT for the work they have put into developing the proposed draft. |
| | **Response:**<br>**The SDT thanks you for your response. The technically correct term for the electric discharge through air is "spark-over". In the Technical Reference Document this term is used. The technical definition of "flash-over" refers to the electric discharge over the surface of insulation when the "withstand" of the air is less than the "withstand" of the insulation and the insulator "flashes over".** | | |

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| | **However, the commonly used term in industry for both phenomena is "flash over". The NERC Glossary definition has actually rolled the technical definition of both terms together into one definition.**<br>**The SDT has decided to use the term "flash-over" in all sections of the Standard except for the derivation of the Gallet equations in the appendix of the Technical Reference Document. Hopefully this will alleviate any confusion.**<br>**The SDT recognizes that the current version of the Standard is zero tolerance and believes it is compelled to write the new version it that way. FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces, and, their belief is the current Standard is zero tolerance.** | | |
| 45 | ITC Transmission | Yes | We were beginning to except Version 3 to the standard but with the addition of "Table 3, Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW" is totally unacceptable. This entire reference should be stricken from the standard. ITC can not support this table #3 and Version 4 is unacceptable. |
| | **Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of ROW in the NERC Glossary.** | | |