Survey Report

Survey Details

Name 2010-07.1 Vegetation Management | FAC-003-4

Description

Start Date 10/30/2015

End Date 12/16/2015

Associated Ballots

2010-07.1 Vegetation Management FAC-003-4 IN 1 ST

Survey Questions

1. Do you agree with the FAC-003-4 table 2 MVCD values? If not, please provide your response below.

- ***Yes***
- ***No***

2. Do you agree with modifying the elevation levels in table 2 to go up to 15,000 feet and 4,267 meters? If not, please provide your response below.

- ***Yes***
- ***No***

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

1. Do you agree with the FAC-003-4 table 2 MVCD values? If not, please provide your response below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 5,6 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rob Robertson - SunEdison - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - Dan Bamber On Behalf of: David Downey, ATCO Electric,1

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer: No

Answer Comment:

The tables are missing columns (or the headers are wrong) and have some number transpositions. In the english (ft) version of the table the range between 13000' and 14000' is missing. Additionaly the rounding mathematics used to generate the tables may not be the most conservative. For clearances one should round up in all instances.

There is no issue with the underlying clearance numbers that resulted from the laboratory testing. The issue is with the translation into the standard. It appears some more quality control and independent review should have been applied.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

While AEP does not object to the newly-proposed English values in Table 2, these values are not equivalent to the metric values provided in the same table. AEP requests that the drafting team review both the English and Metric values, and provide corrections as necessary.

Document Name:

Likes: 0

Dislikes: 0

Roger Dufresne - Hydro-Qu?bec Production - 5 -

Selected Answer: No

Answer Comment:

See comments from TransEnergie

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: No

Answer Comment:

There are several typos in the table. In the "over 2133.6 m to 2438.4 m" column, the cell for 345 kV should be 1.5m, not .5m and the cell for 115 kV should be 0.7m, not .07m.

The added columns on the English table are missing the 13,000-14,000 ft range. The added columns on the Metric table stop at 14000 ft. The 14000-15000 ft column is not there. The two tables are inconsistent.

MVCD in the DC table did not change. Is this correct?

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

Please see WECC's position paper for details

Document Name:

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: No

Answer Comment:

The following is an excerpt from the WECC position paper:

In summary, the following changes should be made before approval:

· Correct the Functional Entity from “Planning Authority” to “Planning Coordinator”

· The added columns in Table 2 for vegetation management over 12,000ft are superfluous and not needed.

· Although not needed, the column for 14,000 to 15,000 is inadvertently skipped.

· Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,

· Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.

· For ease-of-use, the columns from “Over sea level up to 500 ft” and “Over 500 ft up to 1000 ft” should be combined to a single column “Over sea level up to 1000 ft”…only one cell will change by one tenth of a foot in only the 765kV voltage class.

· The elevation columns in the “meters” page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD’s (rounded to within one tenth of a foot) will not change.

· In Table 2 for Direct Current, the MVCD’s are calculated to within one hundredth of a foot – this is an un-workable level of precision.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE noticed the following:

- There is not an “Over 13000 ft up to 14000 ft” column provided. Should there be?
- There is an incorrect value in the MVCD meters table in the last two columns. One column references “….up to 3962m” and the final column references “Over 3692 m….” so there appears to be transposed values
- On Table 2, there is no column for Over 13000 ft up to 14000 ft. The values in the “Over 14000 ft up to 15000 ft” within the Standard match the values of the “Over 13,000 ft up to 14,000 ft” values in the May 14, 2015 Industry Advisory. Is that correct? Based on the nature of the data (a general increase for most, if not all, 1000 ft elevation increase) it does not appear reasonable.
- It does not appear that there is consistency in the values. When you review the voltage levels increasing (e.g. 230 kV to 287 kV) it appears that the MVCD increase (e.g., at “sea level up to 500 ft” the MVCD increase from 4.0 ft to 5.2 ft). The increasing pattern appears to not be followed when it reaches the 345 kV level. The MVCD actually decreases when compared to a 287 kV level. Why does that occur? Was there a different parameter used in the derivation of Gallet’s equation for the 345 kV level? Ascertaining the correct value for the 345 kV level is highly critical for the ERCOT Interconnection (in both measurement type versions of the table.)
- Similar to the comment above, the MVCD for 345 kV lines from 2133.6m to 2438.4m is .5m, which is less than the MVCD of 1.5m and 1.6m for the altitudes immediately before and after in the table. This appears to be a typo and the MVCD for 345 kV lines 2133.6m to 2438.4m should be 1.5m.
- Table 2 for AC Voltages does not include lines at altitudes between 3352.8m and 3353m.
- There appears to be an inconsistency in the “meter” version of Table 2. The “older columns” have decimal point step increases (e.g. “Over 2133.6m up to 2438.4m”) that are carried over to the next columns as a starting point (e.g. “Over 2438.4m up to….”). The new columns do not utilize the same formatting.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

SRP appreciates the opportunity to review and comment on the adjustments to the standard. We support the work of the drafting team, but request a review and revision of the tables to reflect issues identified in the WECC position paper including:

- The column for 14,000 to 15,000 is inadvertently skipped.
- Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,
- Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.
- For ease-of-use, the columns from “Over sea level up to 500 ft” and “Over 500 ft up to 1000 ft” should be combined to a single column “Over sea level up to 1000 ft”…only one cell will change by one tenth of a foot in only the 765kV voltage class.
- The elevation columns in the “meters” page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD’s (rounded to within one tenth of a foot) will not change.
- In Table 2 for Direct Current, the MVCD’s are calculated to within one hundredth of a foot – this is an un-workable level of precision

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter	Segment
Ginette Lacasse	1,3,4,5,6
Entity	**Region(s)**
Seattle City Light	WECC

Selected Answer: No

Answer Comment:

We support WECC Position paper, Dec 7, 2015: Table 2– (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Voter Information

Voter	Segment
Ruida Shu	1,2,3,4,5,6,7
Entity	**Region(s)**

Northeast Power Coordinating Council	NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter	Segment
Patricia Robertson	1
Entity	**Region(s)**
BC Hydro and Power Authority	

Selected Answer: Yes

Answer Comment:

BC Hydro agrees with the revised Table 2 MVCD values based on a Gallet equation gap factor of 1.0. However we would point out one typo on the metric distance table for 345 kV in the 2133.6-2438.4 m elevation column. The distance stated should be 1.5 m not 0.5 m as in the table and should be corrected.

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer: No

Answer Comment:

Hetch Hetchy Water and Power believes the changes recommended in the attached WECC FAC-003-4 position paper should be considered prior to the approval of FAC-003-4.

Document Name: 12-10-15 WECC Position Paper on FAC-003-4.docx

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4

Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4
Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Our group is in support of table 2 however, we have discovered that the values are not equivalent to the metric values provided in the same table. We would requests that the drafting team review both the English and Metric values, and provide corrections as necessary.

Document Name:

Likes: 0

Dislikes: 0

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Voter Information

Voter

Colleen Campbell

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: Yes

Answer Comment:

We agree with the values listed in Table 2, as derived from EPRI's empirical studies.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. Do you agree with modifying the elevation levels in table 2 to go up to 15,000 feet and 4,267 meters? If not, please provide your response below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 5,6 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rob Robertson - SunEdison - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter

Richard Hoag

Segment

1,3,4,5,6

Entity

FirstEnergy - FirstEnergy Corporation

Region(s)

RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - Dan Bamber On Behalf of: David Downey, ATCO Electric,1

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer: Yes

Answer Comment:

Yes, but the tree line in North America may not be that high.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Roger Dufresne - Hydro-Qu?bec Production - 5 -

Selected Answer:

Answer Comment:

See comments from TransEnergie

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5

Entity	Region(s)
Dominion - Dominion Resources, Inc.	

Selected Answer: Yes

Answer Comment:

Table 2 - Minimum Vegetation Clearance Distances (MVCD) For Alternating Current Voltage (feet) is missing the data column located between "Over 12,000 ft" and "Over 14,000 ft". The column "Over 13, 000 ft" is not included in the table.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Hydro-Quebec TransEnergie support NPCC comments

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6

Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Idaho Power's transmission system has no facilities at or near the stated elevation.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: No

Answer Comment:

Do not understand the need to go this high. I believe it is well above the treeline/timberline. If there is no vegetation, there is no need to manage it.

4267 meters is only 14000 feet not 15000 feet.

However, as long as the tables are consistent, we don't have any problems if they go this high.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

Please see WECC's position paper for details

Document Name:

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE inquires: was there any consideration for establishing MVCDs for lines that are below sea level (e.g., New Orleans or Death Valley)?

Please see Texas RE's observations in #1.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter
Ginette Lacasse

Segment
1,3,4,5,6

Entity
Seattle City Light

Region(s)
WECC

Selected Answer: No

Answer Comment:

We support WECC Position paper, Dec 7, 2015: Table 2– (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Voter Information

Voter	Segment
Ruida Shu	1,2,3,4,5,6,7
Entity	**Region(s)**

Northeast Power Coordinating Council NPCC

Selected Answer: No

Answer Comment:

In table 2 Minimum Vegetation Clearance Distances (MVCD meters) the last two column headers are mislabeled. The last two columns should be “Over 3657m up to 3962m and Over 3962m up to 4267m” per the NERC report.

In Table 2 Minimum Vegetation Clearance Distances (MVCD feet), the last two column headers are mislabeled. In the NERC report the last column is labeled 13,000 ft up to 14,000 ft.

Document Name:

Likes: 0

Dislikes: 0

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter	Segment
Patricia Robertson	1
Entity	**Region(s)**
BC Hydro and Power Authority	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

However, the 'feet' and 'meter' versions of Table 2 for AC are either missing a column or the last column is mislabeled.

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer: No

Answer Comment:

Hetch Hetchy Water and Power believes the changes recommended in the attached WECC FAC-003-4 position paper should be considered prior to the approval of FAC-003-4.

Document Name: 12-10-15 WECC Position Paper on FAC-003-4.docx

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4
Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4
Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Voter Information

Voter	Segment
Colleen Campbell	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: No

Answer Comment:

We recommend the SDT consider adding a graph, possibly on a logarithmic scale, to clearly list the values for each elevation. The revised table is congested with the additional information and should be modified for easier readability.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. does not agree with the elevation levels specified in Table 2. There are also a few minor modifications that need correction in Table 2.

Document Name:

Likes: 0

Dislikes: 0

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

na

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

None

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 5,6 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rob Robertson - SunEdison - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - Dan Bamber On Behalf of: David Downey, ATCO Electric,1

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

In the applicability section of FAC-003-4, the Standard applies in bullet 4.2.1 to "Each overhead transmission line operated at 200 kV or higher." Please comment on whether FAC-003-4 applies to non-BES lines in addition to BES lines. For example, if a 230 kV line is excluded from the BES because it is a load serving only radial line, does FAC-003-4 apply to this line as it is a transmission line operated at over 200 kV?

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer:

Answer Comment:

It appears that the standard is moving back to the use of the term Planning Authority. NERC's practice in standards development has been moving toward the term Planning Coordinator as the common definition. This standard shold use Planning Coordinator in a future revision before final industry approval.

4.2.2. *Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Authority. <===== should be Planning Coorindator*

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

AEP agrees with the direction that the project team is taking, and supports their overall efforts. AEP's negative vote is driven solely by the apparent lack of equivalency between the English and Metric values that have been proposed for Table 2, and we look forward to potential corrections in the subsequent version of the draft.

Document Name:

Likes: 0

Dislikes: 0

Roger Dufresne - Hydro-Qu?bec Production - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Dominion supports the additional comments of NPCC.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Hydro-Quebec TransEnergie support NPCC comments

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6

Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment: The NSRF agrees with the associated changes.

Document Name:

Likes: 0

Dislikes: 0

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer:

Answer Comment:

While the proposed FAC-003-4 provides additional clearance, APS believes that there are still gaps to address. The testing was done at the EPRI testing facility but not under all weather, topography, atmosphere conditions and variances in tree species. APS is concerned these clearance distances are still too restrictive to ensure reliability of the grid. To compound the issue, these clearances are real-time observations that don’t take into account line loading (sag), temperature and time of day. APS would recommend an additional 10 feet of clearance to safeguard the reliability of the grid.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

na

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Thank you for the opportunity to comment on the standard.

For appearance, all column widths on the tables should be the same. Values in some of the cells do not line up with the other values. This makes the table look sloppy.

I recognize that the ranges on the Metric table columns are exact translations of the 1000 foot ranges, but the numbers identifying the elevation for each column are not how entities that use the Metric System rather than the English System are going to think. No one is going to think in terms of 914.4 to 1219.2 meters. They are going to think in even numbered terms (900-1200 meters). Taking the direct translation rather than fixed, rounded terms is a slap in the face to those using the Metric System. That would be like labeling the English column 2952.7 - 3937.1 feet. The Metric column ranges should be even meters and the values in the cells adjusted accordingly.

R1 and R2 are identical in every way except the facilities that they refer to. Together they refer to all facilities. The VRFs and VSLs are also identical. I disagree with the need to separate them into two different requirements becasue the facilities in R1 are more significant. Compliance enforecement has the discretion to handle a violation differently if it is an element of an IROL or a Major WECC Path. The standard doesn't need two requirements for the same thing.

We have attached a redline version of FAC-003-4 that includes addtional suggested changes and the reasons for the suggestions.

Document Name: FAC-003-4_Results_Based_Standard_WECC Comments.docx

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

ATC has identified the following recommended improvements for consideration by the SDT to the draft Standard .

- Regarding the Applicability of Facilities Section 4.2.2., American Transmission Company (ATC) recommends revising the language for clarity, to read: “Each overhead transmission line operated below 200 kV identified as an element of *a Planning Horizon* IROL…”
- Similarly, ATC recommends revising the language of R1 to read: “Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of *a Planning Horizon* IROL,…”
- ATC suggests updating the language of R2 to read: Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line (s) which are not either an element of *a Planning Horizon* IROL,…”
- R5 contains a grammatical error and should state: “When *an* applicable…”
- ATC recommends making updates corresponding to those above to Categories 1A, 1B, 2A, 2B, 4A, and 4B identified on pgs. 13-14: “Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of *a Planning Horizon* IROL …,” “Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of *a Planning Horizon* IROL…,” “Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of *a Planning Horizon* IROL…,” “Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of *a Planning Horizon* IROL…,” “Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of *a Planning Horizon* IROL…,” and “Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of *a Planning Horizon* IROL…”
- ATC recommends updating the proposed language in the Guidelines and Technical Basis section (pg. 24) to read: “The special case is needed because the Planning Authorities may designate lines below 200 kV to become elements of *a Planning Horizon* IROL…A line operating below 200kV designated as an element of *a Planning Horizon*...”
- The Project 2010-07.1 Adjusted MVCDs per EPRI Testing section (pg. 26) needs grammatical correction: “The advisory team *was comprised of* NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management…Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation *required* adjustment from 1.3 to 1.0…”
- The Requirements R1 and R2 section (pg. 27) should be updated to read: “R1 is applicable to lines that are identified as an element of *a Planning Horizon* IROL or Major WECC Transfer Path. R2 is applicable to all other

lines that are not elements of *Planning Horizon* IROLs,... The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of *a Planning Horizon* IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of *Planning Horizon* IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of *Planning Horizon* IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant."

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

PGE is in agreement with WECC as outlined in their position paper and is casting a "No" vote for this standard. WECC's position paper is attached.

Document Name: 12-10-15 WECC Position Paper on FAC-003-4.docx

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Duke Energy would like to point out to the SDT, that there appears to be an omission on Table 2 of the MVCD range of “over 13,000ft up to 14,000ft”. The columns currently lists ranges from 12,000ft to 13,000ft, and then moves to 14,000ft to 15,000ft skipping over the 13,000 to 14,000ft range. Duke Energy recommends adding an additional column to include the omitted MVCD range.

Duke Energy would also like to point out that there are some inconsistencies with the number of decimal places that are used in Table 2 of the currently enforceable FAC-003-3. In some instances one decimal place is used (ex. 8.2ft) and others where two decimal places are used (ex. 8.33ft). We recommend that a consistent approach be used going forward regarding the minimum MVCD levels, and that all values use the same number of decimal places in Table 2.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE noticed in R1.1, the table is referenced as FAC-003-Table 2. In the VSLs, the table is referenced as FAC-003-4-Table 2. Texas RE recommends changing the requirement language to match the VSL language to eliminate confusion and clearly indicate the table for version 4 of the standard.

Texas RE noticed the VSL for R2 references FAC-003-4-Table 2 but the Requirement language itself does not. Texas RE recommends the requirement language reference Table 2 in order to be consistent with the VSL language. Should Requirement 2 language include the same phrase, “as shown in FAC-003-Table 2” with or without the “-4” reference, as Requirement 1?

Texas RE inquires: does the table in the supplemental material (titled “Comparison of spark-over……”) need to be changed based on the EPRI review?

Texas RE recommends reviewing the footnotes for consistency. Footnotes 9, 10, and 11 reference Footnotes 4, 5, and 6, while Footnotes 17, 19, and 21 are identical but all include the full language of the footnote. Footnotes 18 and 20 are also identical, but footnote 20 includes the full language instead of "See footnote 18".

For example, Texas RE noticed two footnotes with similar language. On Page 8 of the Standard there is a footnote, #4, that is then referenced on Page 9 by footnote #9: "This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW. "

On Page 11 in Footnote #15 there is a similar sentence to Footnote #4; "Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body."

Texas RE recommends the SDT be consistent with the language of the footnotes.

The Table 2 footnote " + Table 2- Table of MVCD…" is incorrect as the May 14, 2015. NERC Advisory did not include the 14000 to 15000 ft column.

On the Direct Current portion of Table 2, Texas RE noticed there is not a reference regarding line operated at normal voltages "other than those listed" as well. Should there be? Also, why did the SDT not extend the Direct Current portion of the Table to 15000 ft?

Texas RE recommends changing the language of R1 and R2. The Requirements should read: “to prevent encroachments of the types shown below into the MVCD of its applicable lines, operating within their Rating and all Rated Electrical Operating Conditions, which are…..” instead of “operating within its Rating and all Rated Electrical Operating Conditions of types shown below:” The current version reads as if the “types show below” is referencing Rated Electrical Operating Conditions.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

The Bureau of Reclamation supports the drafting team’s proposed revisions to FAC-003-4.

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter	Segment
Ginette Lacasse	1,3,4,5,6
Entity	**Region(s)**
Seattle City Light	WECC

Selected Answer:

Answer Comment:

As mentioned above we are supporting the WECC Position Paper of Dec 7, 2015 as follows:

- Correct the Functional Entity from “Planning Authority” to “Planning Coordinator”
- Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.
- For ease-of-use, the columns from “Over sea level up to 500 ft” and “Over 500 ft up to 1000 ft” should be combined to a single column “Over sea level up to 1000 ft”…only one cell will change by one tenth of a foot in only the 765kV voltage class.
- The elevation columns in the “meters” page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD’s (rounded to within one tenth of a foot) will not change.
- In Table 2 for Direct Current, the MVCD’s are calculated to within one hundredth of a foot – this is an un-workable level of precision.

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1

Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Voter Information

Voter

Ruida Shu

Segment

1,2,3,4,5,6,7

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer:

Answer Comment:

There are inconsistency with the use of terms “Planning Coordinator” and “Planning Authorities”.

NERC has been transitioning from the term planning authority to the term Planning Coordinator over the last several years.

But in this standard it has recently been change back to Planning Authority. We believe that this is the wrong designation.

Document Name:

Likes: 0

Dislikes: 0

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter

Patricia Robertson

Segment

1

Entity

BC Hydro and Power Authority

Region(s)

Selected Answer:

Answer Comment:

BC Hydro recommends changing Planning Authority to Planning Coordinator to align with current terminology.

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer:

Answer Comment:

The SDT has established inconsistency with the use of the designations “Planning Coordinator” and “Planning Authority”. NERC has been transitioning from the term Planning Authority to the term Planning Coordinator, but in this standard revision the Planning Coordinator designation has been changed back to Planning Authority.

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4

Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4
Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer:

Answer Comment:

Page 2 of the Standard….second line of the purpose definition. We would suggest to the drafting team to capitalize ‘vegetation’ since it is a defined term in the NERC Glossary of Terms.

Page 2 of the Standard….In section 4.1.1.1 of the Applicable Transmission Owner. We would suggest to the drafting team to not capitalize ‘Transmission Facilities’ since it is not a defined term in the NERC Glossary of Terms.

Page 2 of the Standard….In section 4.1.2 of the Applicable Generator Owner. We would suggest to the drafting team to not capitalize ‘Facilities’ since it is not a defined term in the NERC Glossary of Terms. However, the term‘Facility’ is defined.

Page 2 of the Standard….In section 4.2.1, 4.2.2, 4.2.3, 4.2.4 of Facilities. We would suggest to the drafting team to capitalize ‘transmission line’ since it is a defined term in the NERC Glossary of Terms.

Page 3 of the Standard….In section 4.3.1 of Generation Facilities (first line). We would suggest to the drafting team to capitalize ‘transmission line’ since it is a defined term in the NERC Glossary of Terms.

Page 3 of the Standard….last paragraph of the Background (first, second, and third line). We would suggest to the drafting team to capitalize ‘reliability standard (s)' since it is a defined term in the NERC Glossary of Terms.

Page 4 of the Standard… bullets 2, 3, 5.). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Also, we make the same suggestions in the last two paragraphs for the same term.

Page 4 of the Standard….last paragraph. We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Page 5 of the Standard…..Requirement R1 (second line). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Additionally, we suggest some alternative language for Requirement R1 to define or identify how these the elements of an IROL and elements of a Major WECC Transfer Path are determined. The suggested language as followed: "Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path that are determined by a particular study; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below".

Page 6 of the Standard….In sections 1.2, 1.3,1. 4 of Requirement R1. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 6 of the Standard…..Measurement M1. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 6 of the Standard….. Requirement R2. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Also, we make the same suggestions in sections 2.2, 2.3, 2.4 for the same term.

Page 7 of the Standard…..Measurement M2. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 7 of the Standard….. Requirement R3 (line 3). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 8 of the Standard….. Requirement R6 (line 2). We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Page 8 of the Standard….. Measurement R6 (line 2). We would suggest to the drafting team to capitalize ‘transmission line’ since it is a defined term in the NERC Glossary of Terms.

Document Name:

Likes: 0

Dislikes: 0

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Voter Information

Voter	Segment
Colleen Campbell	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer:

Answer Comment:

(1) We question the modification from Planning Coordinator to Planning Authority. The NERC Glossary defines the PC, but not the PA. If the SDT is striving for consistency with FAC-014, we suggest developing a SAR to replace the outdated reference of the Planning Authority with the current Planning Coordinator term. It is surprising that the standards still have two terms for a single registered function. The Functional Model Working Group is conducting a review of the NERC Functional Model, and we suggest that the SDT discuss this change with them for guidance going forward.

(2) The timelines of the Implementation Plan are reasonable. However, we recommend copying the same language from the standard to the Implementation Plan for consistency.

(3) We also find Section C. Compliance, Section 1.2 Evidence Retention, second bullet, redundant, as “unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation” is already listed at the beginning of the section.

(4) We thank you for this opportunity to comment.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment:

While Hydro One Networks Inc. feels that the standard needs a few minor modifications and corrections, we generally support the intent of the standard. Hydro One Networks Inc. further supports the comments provided by the NPCC. Hydro One Networks Inc. agrees with the NPCC in that the “Planning Coordinator”, as opposed to the “Planning Authority”, should be an applicable functional entity for the standard.

Document Name:

Likes: 0

Dislikes: 0

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015

Anticipated Actions	Date
45-day formal comment period with ballot	October 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-4
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

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

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3

4.2. Facilities: Defined below (referred to as "applicable lines"),

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

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

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

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

4.3. Generation Facilities: Defined below (referred to as "applicable lines"):

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.6 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do

Deleted: including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities

Deleted: :

Commented [MB2]: This standard applies to all transmission outside the switchyard or substation as identified in 4.2.1 through 4.2.3.

Deleted: , including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities

Commented [MB3]: This extra precision is not needed

Deleted: 09

not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

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

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

5. Effective Date: See Implementation Plan.

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

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

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

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

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

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

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

Formatted: Font: Bold

Deleted:

Formatted: Font: Bold

Formatted: Font: Bold

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

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

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

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

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, will reduce and manage this risk.

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

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station.

Commented [MB4]: "any kind of land" is referring to who owns the land. Easement refers to certain rights to locate a line on the land.

Commented [MB5]: It is already stated "any kind of land" the rest is redundant.

Deleted: whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee,

Deleted: For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities

Deleted: .

However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

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

B. Requirements and Measures

R1. Each applicable Transmission Owner(TO) and applicable Generator Owner(GO) shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable lines operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

1.1 An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

Deleted: (

Deleted:)

Deleted: which are either an element of an IROL, or an element of a Major WECC Transfer Path

Deleted: ;

Commented [MB8]: Is this intentionally excluding a situation where the line is overloaded and sagging…or where it is operating below its rated voltage?

Commented [MB9]: R1 is written to "Prevent encroachments" while 1.1 – 1.4 are written in past tense…a violation only occurs if an encroachment is seen or caused an outage. So inadequate management that will result in an outage as soon as the wind blows a little or the conductor heats up is not addressed.

Deleted: the

---

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

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

[6] 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.

[7] *Id.*

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

Deleted: Examples of

Deleted: a

Commented [MB11]: So you can comply by simply not looking?

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

Commented [MB12]: R1 covers lines that "are" R2 covers lines that "are not" we could simply use one requirement…unless the intent is to have different VSL's or VRF's…however they are the same. We could eliminate R2 and just have R1 cover both.

2.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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

Deleted: Examples of

Deleted: a

R3. Each applicable Transmission Owner and applicable Generator Owner shall have a annual vegetation work plan it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

Commented [MB13]: See wording from R7 – annual vegetation work plan

Deleted: documented maintenance strategies or procedures or processes or specifications

Commented [MB14]: We don't need to guess at every possible title of their maintenance strategy.

Deleted:

---

[8] *Id.*
[9] See footnote 4.
[10] See footnote 5.
[11] See footnote 6.
[12] *Id.*
[13] *Id.*

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

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

M3. Evidence may include copies of the annual vegetation work planthat demonstrates that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when they have confirmed the existence of a vegetation condition could encroach on the MVCD due to a possible change in loading, wind or weather. *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

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

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

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

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines at least once per

Commented [MB15]: It seems these ratings are getting at…the line is designed to withstand movement and sagging due to electrical load, wind, ice, temperature, etc.

Deleted: T

Deleted: maintenance strategies or procedures or processes or specifications provided

Deleted: applicable Transmission Owner and applicable Generator Owner

Deleted: s

Deleted: that is likely to cause a Fault at any moment

Deleted: Examples of

Deleted: e

Deleted: operating within its Rating and all Rated Electrical Operating Conditions

Deleted: ensure continued vegetation management to

Deleted: Examples of

Deleted: a

Deleted: (measured in units of choice - circuit, pole line, line miles or kilometers, etc

Deleted: .)

calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

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

Deleted: Examples of

Deleted:

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

Commented [MB17]: Consider using this term in other requirements.

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M.7 .Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Acceptable

Formatted: Indent: Left: 0.25", Hanging: 0.4", No bullets or numbering

Deleted: Examples of

Deleted: a

[14] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

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

forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

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

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

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

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

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

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a

			transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority

			for that applicable line, but there was intentional delay in that notification.	for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- Link to FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
2	May 9, 2013	Board of Trustees adopted the	Revisions

[16] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

		modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected initial posting October 2015	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[18]	MVCD feet Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD fee Ove 14000 up t 15000
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.0
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9
345	362	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.7ft
230	242	4.0ft	4.1ft	4.2t	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.6ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.5ft

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

Deleted: (

Deleted:)

Deleted: (

Deleted:)

Commented [MB18]: Pretty much impossible to have an applible line above 14000 feet

Commented [MB19]: Missing the 13000 to 14000 column

Commented [MB20]: These entrie are out of line with the others

---

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

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

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[19]
For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[20]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m 300	MVCD meters Over 304.8 m up to 609.6m 600	MVCD meters Over 609.6m up to 914.4m 900	MVCD meters Over 914.4m up to 1219.2m 1200	MVCD meters Over 1219.2m up to 1524m 1500	MVCD meters Over 1524 m up to 1828.8 m 1800	MVCD meters Over 1828.8m up to 2133.6m 2100	MVCD meters Over 2133.6m up to 2438.4m 2400	MVCD meters Over 2438.4m up to 2743.2m 2700	MVCD meters Over 2743.2m up to 3048m 3000	MVCD meters Over 3048m up to 3352.8m 3300	MVCD meters Over 3353m up to 3657m 3600	MVCD meters Over 3657m up to 3962m 3900	MVCD meters Over 3692m up to 4… 42…
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7
345	362	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	0.9m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m

* Such lines are applicable to this standard only if PA has determined such per FAC-014 (refer to the Applicability Section above)
[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

Commented [MB22]: Precision to tenths of meter is not necessary . We can round off these elevations to workable numbers without changing the distances.

Commented [MB21]: This extra column up to 500 ft is not needed – combine with the 1000 ft. column. It only changes two distances by 1/10 ft each.

Commented [MB23]: Out of line

Deleted: 0

Commented [MB24]: Even out column width

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

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

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[21]

For **Direct Current** Voltages feet (meters)

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

Commented [MB25]: Unnecessary precision

Commented [MB26]: See comments for prvious tables

Commented [MB27]: Precision to hundredths of meters is not needed or workable

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

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Authorities may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Authority in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

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

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a

technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

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

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Commented [MB28]: Recommend that we provide the actual equations so users can see how the variable inputs apply.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team comprised NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

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

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant.

Commented [MB29]: Their Violation Risk Factors should be different.or the VSLs should be different. As drafted the two requirements, VRFs, and VSLs are identical.

Compliance enforecement has the discretion to handle a violation differently if it is an lement of an IROL or a Major WECC Path. The standard doesn't need two requirements for the same thing.

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

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

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

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

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

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

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

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

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

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*

2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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

Commented [MB30]: This gets to the point that we should be saying the vegetation cannot encroach on the area defined by all possible conductor movement plus the MVCD around that area.

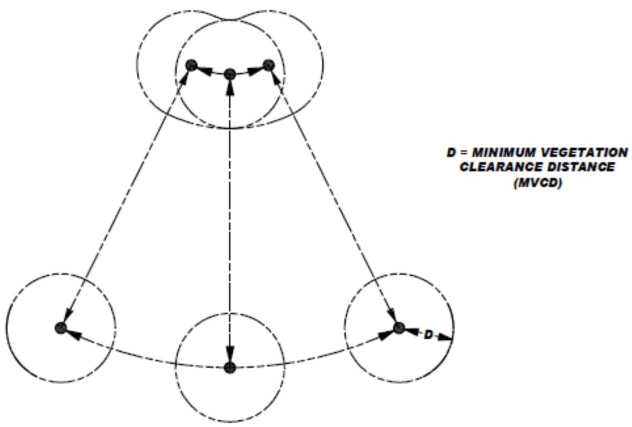

Figure 1

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

Requirement R4:

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

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

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

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

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

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

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

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

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

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

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

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

Requirement R7:

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

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

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

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

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

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

Notes:

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

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

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

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

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

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

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

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

Commented [MB31]: Didn't this capacitor switching just get thrown out in the previous paragraph?

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

Commented [MB32]: Why is this used rather than 1.5 in the previous paragraph?

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

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

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

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

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

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

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

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

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-within MVCD of wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

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

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

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Supplemental Material

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

WECC Position Paper for the initial ballot and non-binding poll of Project 2010-07.1 - FAC-003-4 Transmission Vegetation Management

Being balloted December 7-16, 2015

NERC is conducting a formal comment period and an initial ballot for FAC-003-4 Transmission Vegetation Management. The ballot is open December 7 - 16, 2015.

Members of the Project 2010-07.1 Ballot Pool **are encouraged to vote NO** because the posted version requires further corrections and revision.

Background Information

In FERC Order No. 777, the Commission directed NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing." NERC retained the Electric Power Research Institute (EPRI) to conduct testing to support appropriate Minimum Vegetation Clearance Distances (MVCDs) specified in NERC Reliability Standard FAC-003-3. The MVCDs in the Standard are calculated based on application of the Gallet equation which incorporates a gap factor that reflects the shape of objects that may flash over to the line. The preliminary test result findings determined that the gap factor applied in the Gallet equation requires adjustment. The adjustment will increase MVCDs for all alternating current system voltages covered by Table 2 of the Standard.

Summary of Changes

Revisions from FAC-003-3 reflected in FAC-003-4 include:

- As a result of the studies, the Minimum Vegetation Clearance Distances have been increased by some 30%.
- Table 2, which contains MVCD's at different elevations above sea level, has been expanded to cover line elevations up to 15,000 ft.
- In the Functional Entities section, the term **Planning Coordinator** was inadvertently changed to **Planning Authority.**
- Other Miscellaneous Changes

WECC Review of Changes

Our review indicates that while generally acceptable, the proposed changes need further work before the standard is ready for approval. It is also noted that the increased distances resulting from the EPRI study are substantial and should be considered as such in the voting process. In summary, the following changes should be made before approval:

- Correct the Functional Entity from "Planning Authority" to "Planning Coordinator"

- The added columns in Table 2 for vegetation management over 12,000ft are superfluous and not needed.
- Although not needed, the column for 14,000 to 15,000 is inadvertently skipped.
- Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,
- Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.
- For ease-of-use, the columns from “Over sea level up to 500 ft” and “Over 500 ft up to 1000 ft” should be combined to a single column “Over sea level up to 1000 ft”…only one cell will change by one tenth of a foot in only the 765kV voltage class.
- The elevation columns in the “meters” page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD’s (rounded to within one tenth of a foot) will not change.
- In Table 2 for Direct Current, the MVCD’s are calculated to within one hundredth of a foot – this is an un-workable level of precision.

For these reasons WECC will be voting NO – and we are encouraging others to vote against approval of the FAC-003-4 revision.

A complete copy of the proposed standard and associated materials can be viewed at: http://www.nerc.com/pa/Stand/Pages/Project-2010-07-1-Vegetation-Management.aspx

Voting

The NERC Standards Processes Manual requires that for a negative vote to be counted in the determination of consensus, negative ballots be accompanied by comments explaining the reason for the negative vote. If you vote no, in addition to providing a reason, you should also suggest modifications that would make the standard acceptable. You may provide comments using the electronic form available from the project page identified above.

A non-binding poll for the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) **will not be conducted** due to the fact that only non-substantive changes were made to the requirements, and no changes made to the VRFs and VSLs.

All WECC entities that are registered in the Project 2010-07.1 Vegetation Management Ballot Pool are urged to cast their ballots prior to the close of the ballot period on December 16, 2015.

If you do not wish to cast either an affirmative or negative vote, you are encouraged to cast an abstention to ensure that a quorum is reached.