DUKE ENERGY OHIO EXHIBIT________

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Complaint of Citizens Against Clear Cutting, *et al*.,	)	
Complainants,	)	
v.	)	Case No. 17-2344-EL-CSS
Duke Energy Ohio, Inc.,	)	
Respondent.	)	

DIRECT TESTIMONY OF

KEVIN MCLOUGHLIN

ON BEHALF OF

DUKE ENERGY OHIO, INC.

October 26, 2018

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin McLoughlin, and my business address is 520 Business Park Circle, Stoughton, WI, 53589.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as a Senior Consultant with Environmental Consultants, Inc.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in natural resource management from the State University of New York (SUNY) College of Environmental Science and Forestry and a Master of Science degree in Environmental Management from the same institution.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. The purpose of my testimony is to explain electric utility industry standards for transmission vegetation management (TVM) and best practices and why I believe, based on my experience and personal observations of Duke Energy Ohio's (Duke Energy Ohio or Company) work, that Duke Energy Ohio's vegetation management program is consistent with best practices and provides the soundest option for safety and reliability.

II. HISTORIC PRACTICES AND POLICIES.

Q. PLEASE DISCUSS HISTORIC EVENTS THAT RELATE TO ELECTRIC UTILITY VEGETATION MANAGEMENT POLICIES.

A. It is important to begin with 2003 because a significant blackout of a major portion of the eastern United States occurred that year. That massive blackout was triggered by four 345 kV transmission lines within FirstEnergy's territory in Ohio faulting out to ground via contacts with trees in a cascading manner that were examined in detail by the U.S.-Canada Power System Outage Task Force and its Final Report dated April 2004. That report may be viewed at https://midwestreliability.org/MRODocuments/2003%20Blackout%20Report.pdf. The occurrence of this event has caused the Federal Energy Regulatory Commission (FERC) to certify the North American Electric Reliability Corporation (NERC) as the "electric reliability organization" (ERO) for the United States. NERC was charged with the responsibility to promulgate legally enforceable and mandatory reliability standards for the bulk power system, subject to FERC approval.

Q. HOW DOES THE ESTABLISHMENT OF NERC AS THE ERO RELATE TO DUKE ENERGY OHIO'S VEGETATION MANAGEMENT PROGRAM?

A. In 2007, FERC approved 83 NERC reliability standards, including transmission vegetation management (TVM) standards that prohibit vegetation-related outages from occurring within the right of way (ROW). NERC requires that companies adopt vegetation management policies to eliminate vegetation related power outages from within the ROW. Although the existing NERC regulations only apply to transmission lines of 200 kV or higher, and lines in the neighborhoods related to the complaints filed in this case are 138kV, industry standards and utility best practices require vegetation management to prevent vegetation-related outages for all transmission lines, regardless of the size of the line. Additionally, NERC has filed, and FERC has approved a revised definition of Bulk Electric Systems that includes all transmission lines of over 100 kV making them subject to most Reliability Standards. See "*Report on Transmission Facility Outages During the Northeast Storm of October 29-30, 2011*"fn 54, prepared by FERC and NERC Staff (attached as Exhibit A). Based on my knowledge and experience, these developments mean that there is a strong likelihood that the NERC standards in the future will apply to lines at lower voltages, *i.e.*, less than 200kV but higher than 100kV. Regardless, it is my understanding that Duke Energy Ohio follows the NERC standards along the 138 kV transmission lines at issue in this case.

III. NERC STANDARDS AND APPLICATION.

Q. WHAT IS THE OVERALL PURPOSE OF THE NERC STANDARDS?

A. As previously noted, NERC has promulgated numerous reliability standards, including, among others, a series of TVM standards (see latest revision NERC Reliability Standard FAC-003-4, attached as Exhibit B). The original stated purpose of the first NERC TVM Reliability Standard (FAC-003-1) was: "[t]o improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights of way and minimizing outages from vegetation located adjacent to right of way, maintaining clearances between transmission lines and vegetation on and along transmission right of way, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the NERC." Standard FAC-003-1, Section A(3), p 1 (emphasis added).

Q. HOW DOES NERC DEFINE A UTILITY ROW?

A. NERC has defined a ROW as a segment of land used for the route of a transmission line. A ROW way should be devoid of vegetation that can interfere with a transmission line. The ROW width is the distance between the outer bounds of a ROW.[1] The primary purpose of a high voltage transmission line ROW is the safe and reliable delivery of electrical energy services.

Q. WHY IS IT IMPORTANT TO ADHERE TO NERC STANDARDS FOR ROW CLEARANCE?

A. Between the mandatory NERC reliability standards and the identification of utility best vegetation management practices, Duke Energy Ohio must prevent all vegetation-related outages under all circumstances at all times. Failure to do so can result in up to $1 million dollar per day fines and other sanctions and mitigation measures to be imposed by NERC. Unlike electric distribution lines, and as demonstrated by the 2003 blackout, even a single transmission line failure can be the trigger to begin the cascading loss of other high voltage lines causing thousands of homes and businesses to lose power, devastating commerce, and causing widespread economic collapse and related security and safety risks, with

[1] "*Utility Vegetation Management and Bulk Electric Reliability Report From the Federal Energy Regulatory Commission*", September 7, 2004.

attendant impacts on human health and safety.

Q. WITH RESPECT TO THE ROW IN THE NEIGHBORHOODS OF COMPLAINANTS, WHY DO THESE STANDARDS MATTER IF NOT DIRECTLY APPLICABLE?

A. ROW widths vary significantly among the multitude of transmission owners nationwide. Generally, ROW width increases as line voltage increases. Higher voltage lines require wider ROW because greater separation is needed between conductors. Since ROW width depends on many factors, there is a range of acceptable distances. The ROW in this case contains specific language that allows Duke Energy Ohio to perform clearing of incompatible vegetation to a distance required for the safety of the transmission line—in this case, for a distance of 50 feet on each side of the centerline of the transmission structures. Some electric utilities do not maintain the entire area within its full ROW, which is not considered to be an industry best practice. In fact, in addressing the causes of another incident that resulted in outages involving trees—the October 2011 snow storm—the NERC/FERC Staff report found: "that roughly 25% of the confirmed vegetation-related transmission line outages during the October event were caused by trees that fell into transmission lines from inside a utility's full ROW. These on right of way trees were all located outside the utility's maintained right of way." Based on this finding, the FERC and NERC Staff both recommended that, "where possible and practical, utilities implement the industry best practice of ensuring that danger trees are not present within their full rights-of-way. In particular, to the extent a utility manages vegetation only on maintained rights-of-way rather than full rights of way, it should work toward reclaiming the full ROW width where feasible."

Q. HOW WOULD THAT FERC/NERC STAFF RECOMMENDATION REFERENCE TO "WHERE POSSIBLE AND PRACTICAL" BE FOLLOWED BY AN ELECTRIC UTILITY COMPANY?

A. The utility company should work toward reclaiming the full ROW where the utility company has the legal rights to do so. This means removing all incompatible vegetation from within the ROW. Incompatible vegetation includes those tree and woody shrub species that have the capacity to grow tall enough at or near maturity to interfere with the safe and reliable operation of the transmission line.

Q. PLEASE EXPLAIN HOW DUKE ENERGY OHIO'S VEGETATION MANAGEMENT IMPLEMENTS OR FOLLOWS THIS RECOMMENDATION?

A. Duke Energy Ohio has the legal right to cut, trim, or remove any trees, overhanging branches, or other obstructions both within and without the limits of the ROW, which the Company's engineers or other professionals responsible for vegetation management believe may endanger the safety, reliability and maintenance of the transmission lines and equipment. Duke Energy Ohio focused first on removing incompatible vegetation from within the ROW of the Company's higher voltage transmission lines and is now attempting to reclaim its lower voltage transmission line ROW.

IV. RISK OF FLASHOVER EVENTS.

Q. PLEASE EXPLAIN IN GREATER DETAIL WHY IT IS IMPORTANT FOR ELECTRIC UTILITIES TO MAINTAIN FULL ROW.

A. All TVM best management practices, along with the NERC standards, acknowledge that trees and high voltage power lines cannot coexist in close proximity to one another. Trees grow and sway and the power lines sag and also sway, meaning the distance between the two is constantly changing. Trees do not have to physically come into contact with a high voltage line to cause a line to ground fault. From a distance, a flashover can occur from the line through the air to the tree and thence to ground causing a line to ground fault and putting the line out of service. This flashover distance is referred to as the Minimum Vegetation Clearance Distance (MVCD) in the latest NERC TVM Standard and for 138kV lines, this distance is 2.3 feet in locations under 500 feet above sea level. This distance is not the goal—it is the very minimum distance as determined by both calculations and field measurements that trees should be kept from overhead conductors. As stated in the very same NERC TVM standards, these distances 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."

Q. PLEASE DISCUSS THE RISK OF FLASHOVER IN MORE DETAIL.

A. Flashovers can sometimes occur at greater than anticipated distances under extreme conditions. Also, the gap between the trees and the lines can be compromised very quickly if the line heats up due to high ambient temperatures or temporary emergency loadings. Also, if the wind speed drops below about two miles per hour, the heat from the line cannot be dissipated in a timely manner and the line can sag beyond design.

Q. CAN FLASHOVERS OCCUR EVEN WHEN VEGETATION IS TRIMMED TO WHAT MAY BE CONSIDERED TO BE A SAFE DISTANCE FROM THE TRANSMISSION LINE?

A. Absolutely. I have personally witnessed two flashovers on a 115kV transmission line and another flashover on a 230 kV transmission line. In both instances, the vegetation was measured to have over 5 feet of clearance, which exceeded the minimum acceptable clearances and which I thought would have been adequate to avoid such occurrences.

Q. CAN FLASHOVERS CREATE DANGEROUS SITUATIONS FOR THE ELECTRIC UTILITY'S CUSTOMERS AND OTHERS IN THE GENERAL PUBLIC?

A. Yes. I once consulted for a power company that had a flashover event near a large tree that had been topped rather than removed from below a 345 kV transmission line. In that instance the flashover occurred from the line through the air to the tree, then to ground, then to an underground pipe, and then into the house where that pipe ran. Not only did the flashover cause the transmission line to ground fault and go out of service, it also blew a hole in the bathroom inside the house. Fortunately no one was home or injured in that incident. Notably, that homeowner was like the complainants in this case and had demanded that his tree be trimmed and pruned even though it sat below the transmission line. However, after that incident the homeowner became an advocate for the power company when other homeowners along that transmission line objected to having their trees removed.

Q. IS THERE ANYTHING UNIQUE TO THAT EVENT INVOLVING A 345 KV LINE?

A. Not at all. Flashover events of that nature can occur on any high-voltage transmission lines, including 138 kV lines at issue in this case.

Q. HOW DO ELECTRIC UTILITIES SUCH AS DUKE ENERGY OHIO USE THEIR VEGETATION MANAGEMENT PROGRAMS TO MITIGATE RISKS OF FLASHOVER EVENTS?

A. The need to keep all incompatible tree species from inhabiting the ROW is now the most often adopted TVM strategy. Such tree species are removed well before they become tall enough to cause a clearance problem. This is often accomplished under the rubric of Integrated Vegetation Management (IVM).

Q. WHAT IS INTEGRATED VEGETATION MANAGEMENT?

A. IVM is a method of managing vegetation that entails the highly selective removal of all targeted incompatible vegetation found within the ROW, while at the same time making an effort to retain and foster all the desirable, compatible vegetation such as woody shrubs, vines, herbs, grasses, sedges, etc. These low growing, sun loving, often early successional species of vegetation will, after repeated tree removal, begin to dominate the ROW environs and help preclude the future regrowth and establishment of incompatible trees. The IVM-treated ROW can be divided up into a Wire Zone (WZ) immediately under and to the side of the overhead conductors and a Border Zone (BZ) along the outside edge of the ROW. Duke Energy Ohio has determined that, in the WZ only very short woody shrubs that can achieve heights not taller than seven feet and associated herbaceous plants can be tolerated, whereas in the BZ taller shrubs and very short stature trees (that grow no taller than fifteen feet) can be accommodated. These are reasonable restrictions which adhere to industry best management practices.

Q. PLEASE EXPLAIN THE BENEFITS OF RECLAIMING AND MAINTAINING THIS UTILITY ROW?

A. The benefits of performing IVM upon electric transmission line ROW are numerous. First, in respect to reliability, all the tall growing tree species are targeted for removal at heights well below the conductors. These trees need to be removed early so that they do not grow tall enough to begin to shade out the desirable low growing vegetation that is often sun-loving (shade intolerant). With the attentive effort to spare the desirable low growing species, their number and diversity will naturally increase so that they will cover the ROW environs in a dense fashion, thus making the regrowth of tree seedlings much more difficult and time consuming. When these desirable plants occupy the ROW, there is direct competition with the undesirable trees for physical space because two things cannot occupy the same place at the same time. This is sometimes referred to as physical competition or interference. Then, these low growing plants also will compete with the tree seedlings for light, moisture and soil nutrients. The attentive implementation of IVM also has several well-established environmental benefits. These low growing, ROW maintained, plant community assemblages produce unique habitats for use by numerous wildlife and bird species that require shrub lands, herbaceous cover, and grassy areas for their food, shelter and breeding areas. This type of ROW vegetation condition, produced as a result of implementing IVM, mimic, in many respects, an "Old Field" condition that is rapidly becoming a landscape rarity today. Many sun-loving early successional plant communities found in old fields are continuously perpetuated by implementing IVM on transmission ROW. The old fields are only temporary features on the landscape and will eventually mature into a forested condition, at which point all the early successional plants will be eliminated. These unique ROW habitats provide a diverse array of ecological niches for many early successional species that may include various plants listed as endangered, threatened, rare and protected species. These diverse ROW plants communities have their associated insects dependent upon them, such as pollinators (butterflies and bees) and other micro-organisms that directly depend upon these plants growing in the ROW. Over time, the numerous desirable low growing plants on the ROW will additionally act as a natural impediment to any potential soil erosion that could occur on slopes.

Q. HOW DOES THE LAND USE FOUND ON THE ROW AFFECT TRANSMISSION VEGETATION MANAGEMENT?

A. In short, it should not. Best practices within the electric industry focus on safety and reliability, not the manner in which the land is used along the ROW. Practically speaking however, the type of land use along the ROW can impact the manner in which an electric utility implements TVM best practices. In this case, two distinct land use types repeatedly occur along the 138kV transmission lines ROW. One is a typical suburban residential landscape and the other is an uncultivated wildland in a "brushland" type condition. In both situations incompatible vegetation must be targeted for removal from this ROW. In the landscaped ROW areas, located in close proximity to residences built after the line was already installed, there are numerous tall mature trees that have been purposefully planted along with some more recently established tree saplings and other shrubbery of various heights and stages of maturity. In these residentially landscaped ROW areas all the incompatible vegetation must be carefully removed individually regardless of their current height. All woody materials generated from these ROW tree removal operations must then be handled and managed in a manner consistent with the underlying fee owners' wishes as well as adhering to established and appropriate BMPs for clean-up and site restoration. In the wildland ROW areas, the use of IVM can be performed whereby all the incompatible vegetation is selectively treated and the desirable low growing plant species compatible with the ROW can remain and then both grow and hopefully thrive. Overtime, after the selective removal of incompatible vegetation, these desirable low growing plant communities will multiply and become more diverse within the ROW.

Q. WHY CAN'T TREE TRIMMING/PRUNING BE PERFORMED ROUTINELY FOREVER?

A. Lines over 100kV are usually classified as high voltage transmission and are included in the BES definition by NERC. Then lines in the 34.5 to 69kV range are often referred to as sub-transmission. Under 34.5kV is normally the range of distribution. The major difference between low voltage distribution lines and high voltage transmission lines from a vegetation management perspective is quite stark. The lower voltage distribution lines have distinctive characteristics in that they are frequently located along roads and streets which make them readily accessible to line trucks and other utility equipment. The most customary vegetation treatment for these lower voltage distribution electrical facilities is tree "trimming" or as more accurately referred to as tree "pruning." Individual tree limbs are cut back away from the electric conductors a specified distance based upon voltage and tree growth characteristics. With lower voltage lines the phenomena of having a flashover is minimal to almost nonexistent (again dependent on the specified voltage). For all high voltage transmission lines, such as the 138kV lines in this case, there should be no trimming/pruning occurring at all. Pruning/trimming of tall trees located on high voltage transmission line ROW is a temporary solution to a long-term problem which can only serve to exacerbate the future possibility of a tree contact resulting in a flashover and a line to ground fault. After all, pruning trees causes regrowth or response growth that occurs at a higher rate than normal growth, and the overall size of a tree continues to increase. As a result, the additional growth prompted by ongoing pruning shortens the time period between necessary prunings. Therefore, TVM best practices dictate that electric utility companies should not manage entire transmission systems through pruning. Instead, all incompatible vegetation should be removed, including trees that are large and widely spaced as is most often found in a residential landscape setting. No incompatible vegetation should be allowed within the ROW in such landscaped areas irrespective of their initial height at the time of planting due to their future prospective height growth.

Q. WHY IS CLEAR CUTTING NECESSARY IN SOME SECTIONS OF THE ROW?

A. On wildland ROW situations IVM should be implemented even if it means that an initial ROW reclamation effort must first be performed. ROW reclamation is sometimes necessary for ROW containing copious numbers of tree stems in high density arrangements. Since the ROW is filled with trees due to previous ineffective TVM actions or waiting too long between vegetation management treatments, all trees must now be removed at once in a total reclamation effort. Such sections of ROW occupied by high-density trees leave little room for desirable species to be preserved as the compatible understory vegetation is often sparse due to shading. Hence the complete removal of all incompatible vegetation often appears to leave a clear-cut condition. The open condition of the newly cleared ROW will now be prone to plant invasion by numerous species composed of both desirable low growing plants as well as undesirable tall growing tree seedlings. A follow up IVM treatment in a timely manner that is more selective will remove the newly established incompatible vegetation but now will have some low growing desirable species to preserve. Additional IVM treatments performed cyclically over the intervening years will serve to enhance the extent of cover of the compatible, lower growing plant communities while continuously eliminating the threat posed by tall growing incompatible vegetation.

Q. HOW DOES ROW VEGETATION MANAGEMENT AFFECT THE SAFE AND RELIABLE OPERATION OF A HIGH VOLTAGE TRANSMISSION LINE?

A. The primary purpose of all ROW vegetation management efforts is to insure the safe and reliable transmission of electric energy. Vegetation allowed to grow too close to the lines can have drastic consequences upon safe and reliable operation of these critical energy facilities. As noted above, when vegetation is permitted to grow too close to high voltage transmission lines a flashover can occur from the line through the air to the tree causing a line to ground fault. This line to ground fault then triggers the line to "trip" or "lock-out" resulting in a line outage. In this situation all the electric energy being transported on this line must move onto other transmission lines causing them to perhaps overload and sag further due to the heating of the line. If tall enough, trees growing within the ROW also can also make physical contact by the trees falling on the lines. The sagging of other transmission lines could cause them to likewise fault out and this is known as "cascading" which can lead to a blackout.

Whether a tree-caused outage is instantaneous or sustained, the resultant discharge of 138,000 volts of electricity from line to ground presents a very dangerous situation in the near vicinity of this event. The extreme hazard of this incident is compounded by the close proximity of residences and people for numerous portions of this high voltage transmission facility. The injection of such high voltage into the ground also may allow the electric currents to reach underground metal pipes that extend into the nearby homes thereby exacerbating the potential for material damage and bodily injury. The photograph below depicts such a flashover event whereby a line to ground fault is occurring via a tree. Note that the energy being discharged is substantial and anybody in the vicinity of such a flashover could be severely injured or killed.

Working around high voltage power lines is also a dangerous occupation in and of itself. Logging, the cutting down or even the trimming of large trees is likewise a very dangerous occupation. Hence, the repeated work entailed in trimming and pruning of large trees in the near vicinity of high voltage power lines is, by its very nature, an ongoing hazardous proposition. Electrocution, falls and being struck by falling materials are the primary causes of injury and death when trimming trees around high voltage power lines. In fact, this work is sometimes so risky that the lines must be de-energized before the work can even proceed. The removal of all incompatible vegetation from within the ROW negates the continuous risky need for an electric utility company to constantly remove limbs and branches as they inevitably grow toward the transmission lines.

The next photograph shows the risks assumed by vegetation management specialists when working on trees in close proximity to electric lines.

Additionally, a tree growing directly under the lines must be routinely and frequently "topped" in a manner that most often results in a very deformed appearance with numerous branches relentlessly growing up (sprouting) toward the conductors. This topping effort is often euphemistically characterized as a "crown reduction" endeavor by arborists. The shape of the tree crown after many such "crown reductions" will tend to promote the growth of numerous vertical stems which then expands the distance over which a flashover from the line will be able to travel making a line to ground fault more inevitable. The photograph below depicts one such tree that has been "topped" on more than one occasion.

Q. WHAT OTHER FACTORS MIGHT INFLUENCE AN ELECTRIC COMPANY'S DECISION TO REMOVE INCOMPATIBLE VEGETATION LIKE TREES WITHIN THE ROW WAY AS OPPOSED TO PRUNING OR TRIMMING?

A. There are other instances during which a longer-than-expected flashover may occur or conductors may get closer to trees than the design sag would predict. As previously mentioned, energized transmission lines heat up and then begin to sag. This can occur as a result of variance in wind speed. All the line sag equations call for at least a minimum wind speed of about 2 miles per hour (some as low as 1.4 mph and others as high as 4.0 mph) which will dissipate the heat in the line and keep the line sag well within design parameters. But what happens when the wind speed is less than this minimum or in the rare instance of a "dead calm" when there is no wind at all? Essentially the transmission line will heat up some more and sag below the design limits. Consequently, a line to tree flashover could occur on a tree or shrub of a height that normally would put it well outside the defined wire clearance zone due to the additional sag caused by line heating from lack of sufficient air flow to adequately disperse the heat via convection. This sustained lack of wind (which must occur over a series of spans to seriously degrade the dissipation rate of heat from the conductor) is fortunately a very unusual event. However, such a rare occurrence cannot be ruled out, and electric utility companies routinely seek extra clearance, particularly in the mid-span area, to account for this infrequent possibility.

ROW vegetation managers are also familiar with the occurrences of ‘corona tip burn’ of trees well below (outside) even some of the most conservative wire security zones. Corona tip burn is a result of a phenomenon associated with all energized transmission lines. Under certain conditions, the localized electric field near an energized conductor can be sufficiently concentrated to produce a small electric discharge that seemingly can be drawn away into a nearby object. The geometry of the object is also important as electric fields around sharp objects with low radii of curvature are stronger than around blunt bodies and hence the shape of tree leaves, needles and twigs play a role in how much corona discharge reaches them. Typical transmission-line electric fields may induce corona on the tips of plants. The presence or absence of this corona varies greatly with the shape of the plant and the space potential of induction. As the corona discharges, electrons are flowing through the air from the line to the tip of the tree resulting in the obvious tip burn of leaves and needles from the modest amount of heat generated in this process. This corona caused “tip burn” is often an indicator to

ROW vegetation managers that the vegetation suffering from this condition is now getting a bit too close to the conductors. These flowing electrons from the corona discharge can then cause a partial breakdown of the air around them through the pathway they are travelling which results in the air being ionized to various degrees. If this ionization process continues, the air can turn into plasma which can then readily conduct electricity. Air acts as an insulator, but when it turns into plasma it becomes a conductor. Once the air becomes sufficiently ionized and plasma begins to form, a flashover event can then abruptly occur. It has been said that; "The corona discharge is basically a plasma that is in a transient, formative phase." Kirkham, H. 2012. Applicability of the "Gallet equation" to the vegetation clearances of NERC reliability standard FAC-003-2 iv. Pacific Northwest National Laboratory. (Mar. 2012). So in this corona initiated event, we have a series of steps. First some slight corona discharge between the pointed tip of a tree and the conductor is initiated. Then steadily more is induced as the insulating pathway of air is broken down and/or as the line sags or the tree grows. As more ionization of the surrounding air occurs between the tree and the line, the formation of plasma develops which allows for the flashover to occur. It would thus seem that under this corona induced circumstance that an arc longer than predicted by conventional means could be generated. It is not hard to imagine that the electric field at the end of a growing plant in the vicinity of a power line will be enhanced. If it is enhanced sufficiently to cause local breakdown, there will be an abundance of charge carriers. There is every reason to suppose that a flashover will be facilitated.[2]

[2] *Id*.

Both of these concerns, lower than normal sag and the possibility of a longer than expected flashover pathway, makes tree trimming, particularly at the mid-span sections of a high voltage transmission line, much more problematic. Tree removal is by far the preferred TVM treatment in these situations.

Q. BASED UPON YOUR OWN KNOWLEDGE AND EXPERIENCE, IS THE DUKE ENERGY OHIO ROW VEGETATION MANAGEMENT PROGRAM CONSISTENT WITH INDUSTRY BEST PRACTICES AND SAFE AND RELIABLE UTILITY SERVICE?

A. Yes. I have discussed Duke Energy Ohio's IVM policies in some detail with the Company's engineers and other professionals that have responsibility for TVM and the implementation of IVM. I have also visited the lines in question in this case to determine whether the Company is conducting work consistent with IVM best management practices. My conclusion is that Duke Energy Ohio has prioritized the company's transmission facilities and is working toward the complete removal of incompatible vegetation within the ROW. The absence of all incompatible ROW vegetation will result in the elimination of all vegetation related power outages from within the ROW. This is the stated goal of the NERC TVM standard.

CONCLUSION

Q. WERE ATTACHMENTS 1 AND 2 PREPARED AT YOUR DIRECTION AND UNDER YOUR CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

ATTACHMENT 1

REPORT ON

Transmission Facility Outages During the Northeast Snowstorm of October 29–30, 2011

Causes and Recommendations

Prepared by the Staffs of the

Federal Energy Regulatory Commission *and the* North American Electric Reliability Corporation

Report on Transmission Facility Outages during the Northeast Snowstorm of October 29–30, 2011

Causes and Recommendations

Prepared by the Staffs of the
Federal Energy Regulatory Commission ***and the*** **North American Electric Reliability Corporation**

TABLE OF CONTENTS:

TABLE OF FIGURES:

I. Introduction

On October 29-30, 2011, an unprecedented fall snowstorm hit the Northeastern United States, blanketing the region with up to two and a half feet of heavy, wet snow. Snowfall amounts broke all previous October records throughout the Mid-Atlantic and New England regions. The snowfall totals were most significant in New England, but parts of New York, New Jersey, and Pennsylvania also received well over a foot of snow. On the morning of October 30, near the end of the storm, more than 3.2 million homes and businesses were without power.[1] Thousands were without power for more than a week, some for as long as eleven days. Estimates put storm costs between approximately $1 billion and $3 billion.

Although the vast majority of these customer outages were caused by damage to electric distribution lines,[2] seventy-four transmission lines[3] and forty-four transmission substations[4] also experienced outages of ten minutes or more. Twenty-four of the transmission facilities (twenty-three lines and one substation) that experienced outages are Bulk-Power System (BPS) elements.[5]

---

[1] Over the course of the weekend, more than 4.3 million customers lost power at one point or another. U.S. Department of Energy, Energy Assurance Daily 1 (Oct. 31, 2011), http://www.oe.netl.doe.gov/docs/eads/ead103111b.pdf (showing the non-concurrent, peak reported outages of twenty-two utilities).

[2] Distribution lines, which carry power from the interstate transmission system to retail customers, are typically operated under 100 kilovolts (kV) and are generally regulated by the states.

[3] Transmission lines, which carry power from electric generating facilities to substations connected to the distribution system, are typically operated over 100 kV and generally – but not universally – regulated by the Federal Energy Regulatory Commission (FERC or the Commission) as to rates and terms of transmission service. See Federal Power Act § 201(b)(1), 16 U.S.C. § 824(b)(1). As explained in footnote 5, the Commission also has jurisdiction, pursuant to Section 215 of the Federal Power Act, over the reliability of the bulk-power system. Although some facilities operated under 100 kV are considered to be "transmission facilities" in certain contexts, this report uses that term to refer only to facilities operated at or above 100 kV.

[4] A transmission substation is connected to one or more transmission lines and houses transformers used to step up or step down (increase or decrease) electric energy voltages. Substations also contain, among other equipment, breakers that allow lines to be connected or isolated in order to clear faults or perform maintenance. Transmission substations impacted by the storm are discussed further in Section IV.B.

[5] Section 215(a)(1) of the Federal Power Act defines the bulk-power System as "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy." 16 U.S.C. § 824o(a)(1). With respect to electric reliability, the Commission has jurisdiction over all users, owners, and operators of the BPS. FERC approves mandatory and enforceable Reliability Standards that are developed by the Electric Reliability Organization (ERO), the North American Electric Reliability Corporation (NERC), that apply to those BPS users, owners and operators registered by NERC. The Commission has adopted, at least for an initial period, NERC's definition of the term Bulk

In light of, among other things, the scope and seriousness of the October snowstorm event, the number of customers and states impacted, the duration of some of the outages, the storm's impact on entities subject to the Commission's jurisdiction, and the level of interest of the public and elected officials in the event, the Commission initiated an inquiry in November 2011 focused on the transmission- and BPS-related impacts of the storm. NERC also began an inquiry into the storm's effect on the BPS, and FERC and NERC combined their efforts into one joint inquiry. NPCC, which had been assisting NERC in its assessment of the storm event, also joined the inquiry team.

From the outset, this joint inquiry focused on determining the causes of the transmission facility outages and on the steps utilities could take to improve their performance in maintaining grid reliability during the next large snowstorm or similar weather event. The purpose of the inquiry has not been to investigate whether particular companies violated the Reliability Standards or other applicable statutes and regulations. NPCC, NERC, and FERC will follow their regular processes in identifying and pursuing any potential Reliability Standards violations. Nor has the purpose of this inquiry been to propose new or revised Reliability Standards or other regulations.

During the course of the inquiry, FERC, NERC, and NPCC staff obtained a significant amount of data from a variety of affected entities. Staff issued a first set of seven multi-part data requests to the thirty-six NERC-registered Transmission Owners and Transmission Operators[6] in the NPCC region, and sent a set of twenty-one multi-part data requests to those entities that reported experiencing transmission facility outages during the event. Staff conducted numerous follow-up calls and requested additional information from a number of entities. Staff also interviewed representatives of Northeast Utilities, the parent company of the three utilities that experienced the most

Electric System (BES) for application of the Reliability Standards. The current definition of the BES is: "as defined by the [Regional Entity,] the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 75, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). The Northeast Power Coordinating Council (NPCC), the NERC-certified Regional Entity for the states affected by the October snowstorm, uses a performance-based test (rather than a voltage-based bright line) to determine which facilities in its region are subject to the Reliability Standards, and calls those facilities "Bulk Power System elements." *See* NPCC DOCUMENT A-10, CLASSIFICATION OF BULK POWER SYSTEM ELEMENTS (2007). Because the transmission facility outages caused by the October snowstorm occurred only in the NPCC region, this report uses NPCC's term "BPS elements."

[6] A Transmission Owner is an entity "that owns and maintains transmission facilities." A Transmission Operator is an entity that "is responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." NERC, *Glossary of Terms Used in Electric Reliability Standards* (Feb. 8, 2012), http://www.nerc.com/files/Glossary_of_Terms.pdf.

transmission facility outages. Staff visited approximately twenty transmission sites on a three-day visit to Connecticut, Massachusetts, and New Hampshire. Staff reviewed relevant reports issued by the affected utilities and independent entities.

A number of agencies in several states affected by transmission and distribution facility outages during the October snowstorm are conducting their own inquiries into utility performance before, during, and after the event. Staff consulted with many of these state agencies, monitored their public proceedings, and discussed with them the report's preliminary findings and recommendations. Staff held outreach meetings with the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, and the North American Transmission Forum, and also shared with them, on a non-public basis, the report's preliminary findings and recommendations. Feedback provided by state agencies and industry associations was considered in preparing this report.

This report: (1) presents staff's assessment of the October snowstorm event, including its impacts on transmission facilities and the BPS, and the causes of transmission facility outages; (2) discusses the applicability of the transmission vegetation management reliability standard to the event; and (3) provides a number of recommendations to industry that, if implemented, could improve utilities' performance and enhance transmission grid reliability during the next large snowstorm or similar event.

II. Executive Summary

The early autumn snowstorm that hit the Northeast on October 29-30, 2011, was unprecedented in the amount of snowfall it produced and particularly devastating because of the untimely combination of several factors. As much as two and a half feet of heavy, wet snow fell at a time when many trees still had their leaves, following a warm, rainy period that left the ground unfrozen, saturated, and soft. The quantity of snow held by the unusually top-heavy trees, coupled with the soft, wet ground, resulted in a great number of healthy trees, most outside of utility rights-of-way,[7] being uprooted and falling onto distribution and transmission lines.

The storm left a trail of destruction that primarily affected distribution systems. Distribution lines were damaged in an estimated 50,000 locations ("trouble spots") throughout the Northeast.[8] Millions of customers[9] served by more than two dozen utilities lost power. Tens of thousands of customers served by Connecticut Light & Power Company (CL&P) were without electricity for more than a week, and some customers served by CL&P were without service for eleven days.[10]

Most of the damage, and customer outages, was due to impacts to the distribution system, which is generally subject to state or local regulation. The transmission system, which is subject to the Commission's jurisdiction, was impacted as well, but it caused less than 5% of customer outages at the storm's peak. Seventy-four transmission lines and forty-four transmission substations experienced sustained outages.[11] Transmission line outages were responsible for approximately 130,000 customer outages around the storm's peak. Most of these outages lasted for less than two days, and none lasted for more than five days. Nearly three-quarters of all of the transmission outages were

---

[7] Utilities rarely own the land on which they site transmission lines. Instead, utilities obtain rights, usually in the form of an easement, over portions of property owned by others. The easement allows the utility to construct, maintain, and operate transmission facilities and vegetation over a defined area of land, the "right-of-way."

[8] A "trouble spot" is a location where there is damage to a line requiring crew response to make conditions safe for the public, repair damage, and restore power.

[9] In the utility industry, the term "customer" generally refers to a single meter, whether at a residence, a retail store, or a factory; it does not refer to each person served at that meter.

[10] *See* WITT ASSOCIATES, CONNECTICUT OCTOBER 2011 SNOWSTORM POWER RESTORATION REPORT 11 (Dec. 1, 2011), *available at* http://www.wittassociates.com/assets/860/CTPowerRestorationReport20111201_FINAL_1_.pdf.

[11] For purposes of this report, facility outages lasting ten or more minutes are considered "sustained" outages.

caused when trees weighed down with heavy, wet snow fell onto transmission lines. Although most of the damage and outages were on the distribution system, this report addresses impacts on, and recommendations for, the FERC-jurisdictional transmission system.

Partly as a result of the August 14, 2003 blackout across the Northeast and Canada, which was caused in part by trees growing too close to transmission lines,[12] Congress passed legislation requiring the Commission to enact mandatory and enforceable Reliability Standards. One of those standards, FAC-003-1 (Transmission Vegetation Management Program), requires Transmission Owners to develop transmission vegetation management programs. These programs must include a schedule for vegetation inspections and specific vegetation clearance distances around transmission lines, have annual vegetation management work plans, and report certain vegetation-related outages.

This Standard's applicability to this event is limited in that FAC-003-1 only applies to transmission lines operated at voltages of 200 kV and above, plus any lower voltage lines identified by the applicable Regional Entity as critical to the reliability of the electric system in the region — and NPCC has not designated any lower-voltage facilities as critical for the purpose of applying FAC-003-1. In fact, FAC-003-1 applied to only one transmission facility forced out of service due to vegetation contact — a 345 kV transmission line in Connecticut — and that line outage did not cause any loss of service to customers. To the extent that a state does not have vegetation management standards governing transmission lines operated over 100 kV and the relevant Regional Entity has not designated lines operated under 200 kV as critical to the region's reliability for the purpose of applying FAC-003-1, lines operated between 100 kV and 200 kV in that state would not be covered by any federal or state vegetation management standard.

In addition, the Standard's applicability to the October event is limited because it does not specifically address off-right-of-way vegetation management. Further, although FAC-003-1 requires each Transmission Owner to "prepare and keep current, a formal transmission vegetation management program" that must include the Transmission Owner's objectives, practices, approved procedures, and work specifications,"[13] beyond this, each Transmission Owner has flexibility on the specific content of its vegetation

[12] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations 139 (Apr. 2004), *available at* http://www.nerc.com/filez/blackout.html.

[13] Reliability Standard FAC-003-1, at Requirement R-1.

management program, including specific direction on how to address danger trees[14] outside of Clearance 1[15] but within the right-of-way.

This report makes several recommendations to help reduce the adverse impacts of future, similar weather events on the transmission system, including: (1) where appropriate, taking targeted steps to address off-right-of-way danger trees; (2) employing best practices in managing vegetation on full rights-of-way; (3) laying the foundation for effective vegetation management when establishing new rights-of-way; and (4) enhancing storm preparedness and response plans as needed. In addition, staff recommends increasing reporting of vegetation-caused outages and improving the content of required disturbance reports.

[14] A danger tree is any tree that, if it fell, could contact a transmission line. *See*, *e.g.*, Accredited Standards Comm. (ASC) A300, Tree Care Indus. Ass'n, American National Standard for Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance — Standard Practices (Integrated Vegetation Management a. Electric Utility Rights-of-Way) 72.5 (2006) [hereinafter ANSI A300].

[15] Clearances are defined and discussed in more detail in Section VII.A.

III. The October 29–30, 2011 Nor'easter

An unprecedented early fall snowstorm blanketed the upper East Coast with up to two-and-a-half feet of snow in about a twenty-four hour period spanning October 29–30, 2011. Significant October snowstorms are rare, and the 2011 storm broke records throughout the Northeast. While the storm and its impacts on trees and power lines were not unanticipated, the severity of the storm exceeded forecasts, and its repercussions were wide-ranging and severe.

A. Forecasts and Utility Preparations

By early in the afternoon of Thursday, October 27, 2011, weather agencies had issued forecasts that an unusual October Nor'easter would hit the New England and the Mid-Atlantic states on Saturday, October 29.[16] Several inches of snow were predicted to fall across the Northeast, and that day's forecasts warned that the coming storm would bring down trees and power lines across the region.[17] Predictions of maximum total snowfall amounts increased rapidly from October 27 to October 29. By the morning of October 29, forecasters were predicting up to fifteen inches of snow in some areas.[18] The snow was expected to begin falling in the late afternoon or early evening of October 29.[19]

A number of utilities began preparations for the storm on Friday, October 28. In the lead-up to the storm, they held internal planning meetings, increased staff in

[16] *See*, *e.g.*, CL&P Resp. to Data Req. PURA-02, Q-EL-014, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 23, 2011 (providing the Telvent weather report from 1:00 p.m. on October 27, 2011, which mentioned a storm arriving on October 29, 2011). A Nor'easter is a severe winter weather event that produces heavy snow or rain, severe winds, and significant waves. A Nor'easter gets its name from the strong northeasterly winds blowing in from the ocean ahead of the storm and over coastal areas. Nat'l Oceanic & Atmospheric Admin., *National Weather Service Glossary*, http://www.weather.gov/glossary/.

[17] *See*, *e.g.*, CL&P Resp. to Data Req. AG-03, Q-AG-117-SP01, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 18, 2011 (providing National Weather Service briefing slides used by CL&P to prepare for the storm).

[18] *See*, *e.g.*, CL&P Resp. to Data Req. PURA-02, Q-EL-014, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 23, 2011 (providing the Telvent weather report from 6:00 a.m. on October 29, 2011, which predicted up to fifteen inches of snow in western Massachusetts).

[19] Nat'l Oceanic & Atmospheric Admin., *Rare October Winter Storm in the Northeast* (Oct. 28, 2011), http://www.nnvl.noaa.gov/MediaDetail2.php?MediaID=874&MediaTypeID=1.

operations centers, and placed in-house and contract field crews on call.[20] Regional mutual aid groups, through which utilities can request line restoration assistance from other utilities, also held conference calls. However, due in part to the moderate snowfall amounts in weather predictions from that morning, few utilities requested assistance on October 28.[21] Nor did many utilities make mutual assistance requests on the morning of Saturday, October 29; at that point, there was a general understanding that utilities would be holding their crews in order to respond to the event in their own service territories.[22] However, snowfall amounts exceeded forecasts, and by Saturday afternoon, utilities began to see that more manpower would be required to address the rapidly increasing outages. Many utilities then began requesting aid from the mutual assistance groups.[23] But because the storm was so widespread — and demand was so great — there were few regional crews immediately available.[24] In addition, there generally was only limited pre-staging of crews (i.e., positioning field workers at locations around a utility's service territory before a weather event so that they will be on the scene to make repairs as soon as the storm is over).

Some utilities — in particular, CL&P — have faced criticism at the state level for inadequate storm preparation, including failing to request mutual assistance earlier or to pre-stage field crews in order to speed response times.[25] Utility emergency preparation and response is almost entirely outside of the Commission's jurisdiction.[26] However, as discussed below, staff's review of the impact of utility preparation and response on transmission restoration found no indication that inadequate preparation materially

---

[20] *See*, *e.g.*, Davies Consulting, Final Report: Connecticut Light and Power's Emergency Preparedness and Response to Storm Irene and the October Nor'easter 19 (Feb. 27, 2012), *available at* http://media2.wtnh.com/docs/Storm-Review-Final-Report.pdf

[21] *See*, *e.g.*, Witt Associates, *supra* note 10; Central Hudson gas & Electric Corp., 16 NYCRR — Part105 Compliance Filing: Report and Evaluation of October 2011 Snowstorm, October 29–November 4, 2011, at 22-23 (Jan. 5, 2012), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={23000E96-EBCF-45C1-BB29-387EF9943C33}; Davies Consulting, *supra* note 20, at 19.

[22] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note10, at 21.

[23] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note 10, at 21.

[24] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note 10, at 21.

[25] *See, e.g.*, JOE MCGEE ET AL., REPORT OF THE TWO STORM PANEL, PRESENTED TO: GOVERNOR DANNEL P. MALLOY 10–11 (Jan. 9, 2012), *available at* http://www.governor.ct.gov/malloy/lib/malloy/two_storm_panel_final_report.pdf; WITT ASSOCIATES, *supra* note 10, at 2-3.

[26] Although several Emergency Operations Reliability Standards deal with registered entities' responses to emergency situations, those Standards are focused on BPS operation issues, and not more conventional preparation and response issues like employee training, staffing levels, or field crew response.

hindered restoration of transmission facilities, as opposed to the more serious preparation and restoration problems reported on the distribution side.

B. Storm Produces Record Amounts of October Snowfall

Not long after the storm began, it became clear that snowfall totals would exceed projections. Wet snow began falling in the late morning of October 29.[27] Snowfall was heavy by mid-day, and it fell quickly: up to three inches per hour for sustained periods.[28] Within about twenty-four hours, some areas had received two-and-a-half feet of snow. The highest amounts of total snowfall were in Massachusetts, where Peru recorded 32 inches, and in New Hampshire, where Jaffrey recorded 31.4 inches.[29] The storm set records for October snowfall across the region. On October 29 alone, Hartford, Connecticut, received 12.3 inches of snow, far surpassing the previous October record of 1.7 inches.[30] That same day, Concord, New Hampshire, received a record 13.6 inches of snow, and Worcester, Massachusetts, received a record 11.4 inches.[31] The previous records were 3.0 inches and 7.5 inches, respectively.[32]

---

[27] Nat'l Weather Serv., *October 29th Historic Early Season Snowstorm*, http://www.erh.noaa.gov/okx/StormEvents/10292011/index.html; DAVIES CONSULTING, *supra* note 20, at 18.

[28] Nat'l Weather Serv. Forecast Office, Boston, Mass., *Review of Snow-tober 2011*, http://www.erh.noaa.gov/box/sigevents/Snowtober_2011/

[29] Nat'l Weather Serv., *Significant Weather Event: Oct. 29–30, 2011*, http://www.erh.noaa.gov/box/displayEvent.php?event=Oct_29-30_2011&element=snow.

[30] Nat'l Climatic Data Ctr., *CT Daily Snowfall Records Set in October 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/00?sts[]=CT#records_look_up.

[31] Nat'l Climatic Data Ctr., *MA Daily Snowfall Records Set on October 29, 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/29?sts[]=MA#records_look_up (providing daily snowfall records for cities in Massachusetts on October 29, 2011); Nat'l Climatic Data Ctr., *NH Daily Snowfall Records Set on October 29, 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/29?sts[]=NH#records_look_up (providing daily snowfall records for cities in New Hampshire on October 29, 2011).

[32] Nat'l Weather Serv., *Concord Climate Data For the Year 2011* (Jan. 18, 2012), http://www.srh.noaa.gov/data/GYX/CLACON; Nat'l Climatic Data Serv.; *MA Monthly Snowfall Records Set in 2011*, http://ncdc.noaa.gov/extremes/records/monthly/snow/2011/10/00?sts[]=MA#records_look_up.

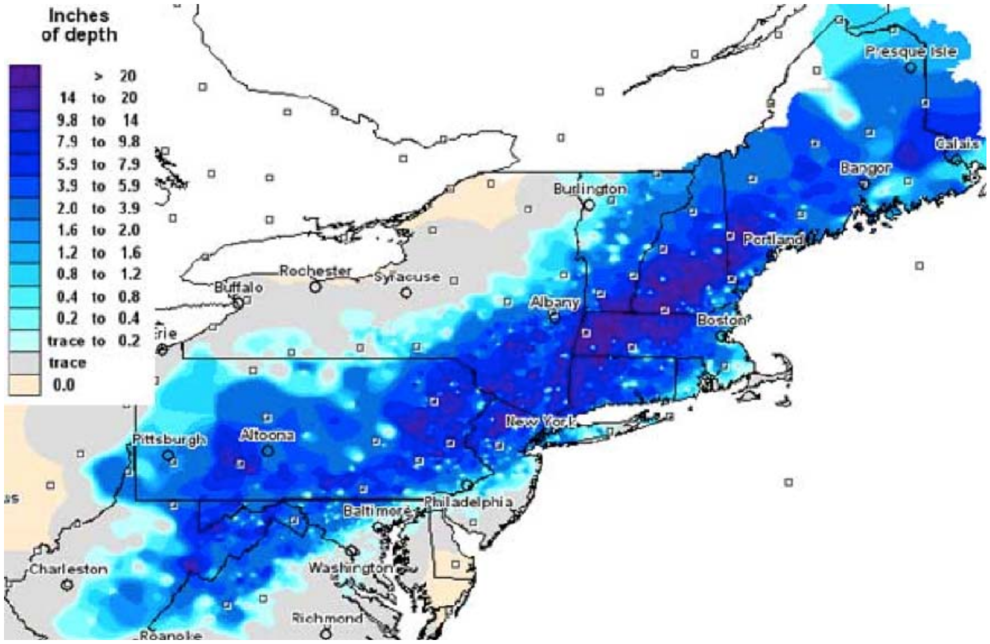

Figure 1: Snowfall Totals Across the Northeast on October 30, 2011

Source: NOAA, nohrsc.noaa.gov/interactive

The National Weather Service called the October Snowstorm a "rare and historic October Nor'easter"[33] and rated it as the strongest fall storm on record for the Northeast region.[34] Connecticut Governor Dan Malloy said that "a review of state records dating back to 1650 indicates that this storm is the most severe October Nor'easter in Connecticut history."[35] The only other notable October snowstorm in New England in the last one hundred and fifty years, which occurred on October 4, 1987, was far less destructive. That storm produced between six and twenty inches of snowfall from Albany, New York, to the Western Berkshires in Massachusetts, and caused only about 300,000 customer outages,[36] compared to the more than 3 million outages caused by the October 2011 storm.

---

[33] Nat'l Weather Serv., *Winter Storm Summary for October 29, 2011 Event*, http://www.erh.noaa.gov/phi/show_wss.php.

[34] Email from NOAA staff to FERC staff (Mar. 15, 2012) (on file with OE staff). The October snowstorm is the only October storm to be ranked by NOAA among the 45 highest-impact snowstorms that have affected the Northeast urban corridor. Nat'l Climatic Data Ctr., *The Northeast Snowfall Impact Scale*, NOAA, http://www.ncdc.noaa.gov/snow-and-ice/rsi/nesis.

[35] Letter from Dannel P. Malloy, Conn. Governor, to Barack Obama, President (Nov. 11, 2011) [hereinafter Malloy Letter].

[36] Robert D. McFadden, *Early Snowstorm Covers Northeast*, N.Y. TIMES (Oct. 5, 1987), http://www.nytimes.com/1987/10/05/us/early-snowstorm-covers-northeast.html?pagewanted=all&src=pm.

C. Leafy Trees and Prior Rainfall Compound the Impact of the Snowstorm

The effects of record amounts of heavy, wet snow were particularly severe because the snow fell across densely wooded areas where deciduous trees had not yet lost many of their leaves. Due to an unusually warm and wet September and October, leaf drop was significantly lower than normal for late October. For example, before the October storm, most of Massachusetts and Connecticut had only experienced "Moderate" — rather than the typically "High" — leaf drop.[37] The weight of snow on the leaves put significant strain on trees, causing limbs to snap and entire healthy trees to fall.

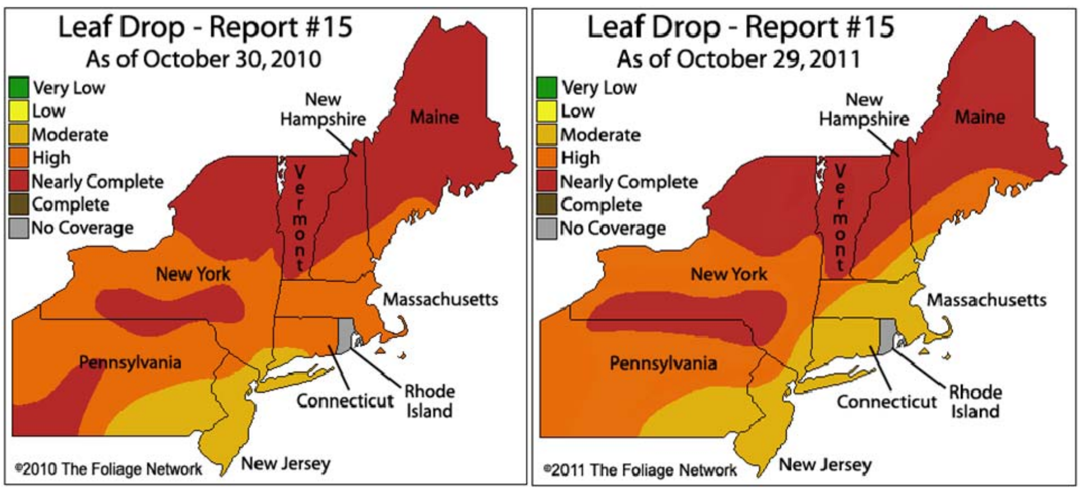

Figure 2: Leaf Drop Reports, October 2010 vs. October 2011
Source: The Foliage Network

Moreover, the ground throughout much of the Northeast was saturated due to an abnormally wet year — including significant August rainfall from Tropical Storm Irene. In fact, August 2011 was the wettest month on record in the Northeast since recording began in 1895.[38] Because the saturated ground had not yet frozen, the weight of the

---

[37] *See Report #15 – Oct. 29, 2011*, THE FOLIAGE NETWORK, http://www.foliagenetwork.net/index.php?option=com_content&view=article&id=333:ne-foliage-report-15-2011&catid=34:northeast-us&Itemid=68; *Report #15 – Oct. 30, 2011*, THE FOLIAGE NETWORK, http://www.foliagenetwork.net/index.php?option=com_content&view=article&id=275:ne-foliage-report-10302010&catid=62:northeast-us&Itemid=85.

[38] In August 2011 an average of 8.53 inches of precipitation was recorded in the Northeast, while the 20th century regional average is only 3.85 inches. Nat'l Climatic Data Ctr., *Precipitation Rankings August 2011 Northeast*, NOAA, http://www.ncdc.noaa.gov/temp-and-precip/ranks.php?parameter=pcp&state=101&div=0&periods[]=1&month=8&year=2011. The year 2011 was also the wettest year on record for the Northeast since 1895: an average of 56.04 inches of precipitation was recorded, while the 20th century average is only 41.08 inches. Nat'l Climatic Data Ctr., *Precipitation Rankings December 2011 Northeast*, NOAA, http://www.ncdc.noaa.gov/temp-and-precip/ranks.php?periods%5B%5D=12&parameter=pcp&year=2011&month=12&state=101&div=0.

heavy, wet snow on leafy trees caused many healthy trees across the region to uproot. On November 1, 2011, the Connecticut Department of Transportation estimated there were 24,000 trees downed on Connecticut roads alone. As explained by Governor Malloy: [39]

> "*The combination of heavy wet snow and near freezing air caused adherences of the snow to all objects including trees, which had not yet lost their seasonal foliage. The weight of the snow on trees and power lines, combined with very wet soils as a result of Tropical Storm Irene and the remnants of Tropical Storm Lee, quickly overwhelmed the ability of trees to remain upright under the added weight. This added weight de-limbed hundreds of thousands of trees and uprooted tens of thousands of additional trees in just 12 hours.*"

The October snowstorm crippled much of the Northeast. As noted above, more than 3 million customers lost electric power. Activity in the affected states ground to a halt: many roads were impassable and scores of schools and businesses closed.[40] States of emergency were declared in many states, including Connecticut,[41] Massachusetts,[42] New Hampshire,[43] and parts of New York.[44] News reports identified at least twenty-two storm-related deaths.[45] The National Oceanic and Atmospheric Administration estimates the costs of the storm to be between $850 and $900 million, and one unofficial estimate puts the costs at more than $3 billion.[46]

---

[39] *See* Malloy Letter, *supra* note 35.

[40] *See* Lauren Keiper, *Millions Without Power After US Northeast Snowstorm*, REUTERS (Oct. 31, 2011), http://www.reuters.com/article/2011/10/31/uk-weather-northeast-idUSLNE79U02Y20111031.

[41] Press Release, Gov. Malloy Declares State of Emergency (Oct. 29, 2011), *available at* http://www.governor.ct.gov/malloy/cwp/view.asp?A=4010&Q=.

[42] Press Release, Governor Lynch Requests FEMA's Reconsideration of Emergency Disaster Declaration (Nov. 2, 2011), *available at* http://www.governor.nh.gov/media/news/2011/110211-emergency.htm.

[43] Press Release, Governor Patrick Meets with Utility Company Officials on Storm and Power Recovery Efforts (Oct. 31, 2011), *available at* http://www.mass.gov/governor/pressoffice/pressreleases/2011/111031-storm-power-recovery.html.

[44] Press Release, Governor Cuomo Declares State of Emergency for Counties Hit Hard by Winter Storm (Oct. 29, 2011), *available at* http://www.governor.ny.gov/press/10292011stateofemergency.

[45] CNN Wire Staff, *Freak Snowstorm Blamed for at Least 22 Deaths*, CNN (Nov. 3, 2011), http://articles.cnn.com/2011-11-03/us/us_east-coast-storm_1_carbon-monoxide-poisoning-cl-p-power-outages?_s=PM:US.

[46] AON BENFIELD, OCTOBER 2011 MONTHLY CAT RECAP – IMPACT FORECASTING 2 (Nov. 3, 2011), *available at* http://thoughtleadership.aonbenfield.com/ThoughtLeadership/Documents/201111_if_monthly_cat_recap_october.pdf; Mary O'Leary, *Gov. Malloy: "What We Need is Action" on Connecticut Power Crisis*, NEW HAVEN REGISTER (Nov. 2, 2011), http://www.governor.ct.gov/malloy/cwp/view.asp?A=11&Q=489996 (quoting Governor Malloy as anticipating

IV. Significant and Widespread Damage to Electric Delivery Infrastructure

The October storm's historic snowfall and resulting tree damage devastated the system of high and low voltage wires that distribute power across the Northeast, leaving approximately 3.2 million customers from Pennsylvania to Maine without power near the end of the storm. The vast majority of the damage to electric delivery infrastructure was to the distribution system. However, the storm's impact on transmission facilities was also significant. Seventy-four transmission lines in a half-dozen states experienced sustained outages.

A. Distribution Facility Damage and Customer Impact

Exact measures of the total physical damage to distribution systems are hard to determine, but there were an estimated 50,000 separate locations across the Northeast where utility crews were required to remove trees from or physically repair distribution lines ("trouble spots"). This serious and widespread damage to distribution facilities caused more than 95% of customer outages. The map on the next page overlays a snapshot of several utilities' customer outages on a map showing snowfall totals across the Northeast.

storm costs would exceed $3 billion); Email from NOAA staff to FERC staff (Mar. 29, 2012) (estimating costs at between $850 million and $900 million) (on file with OE Staff).

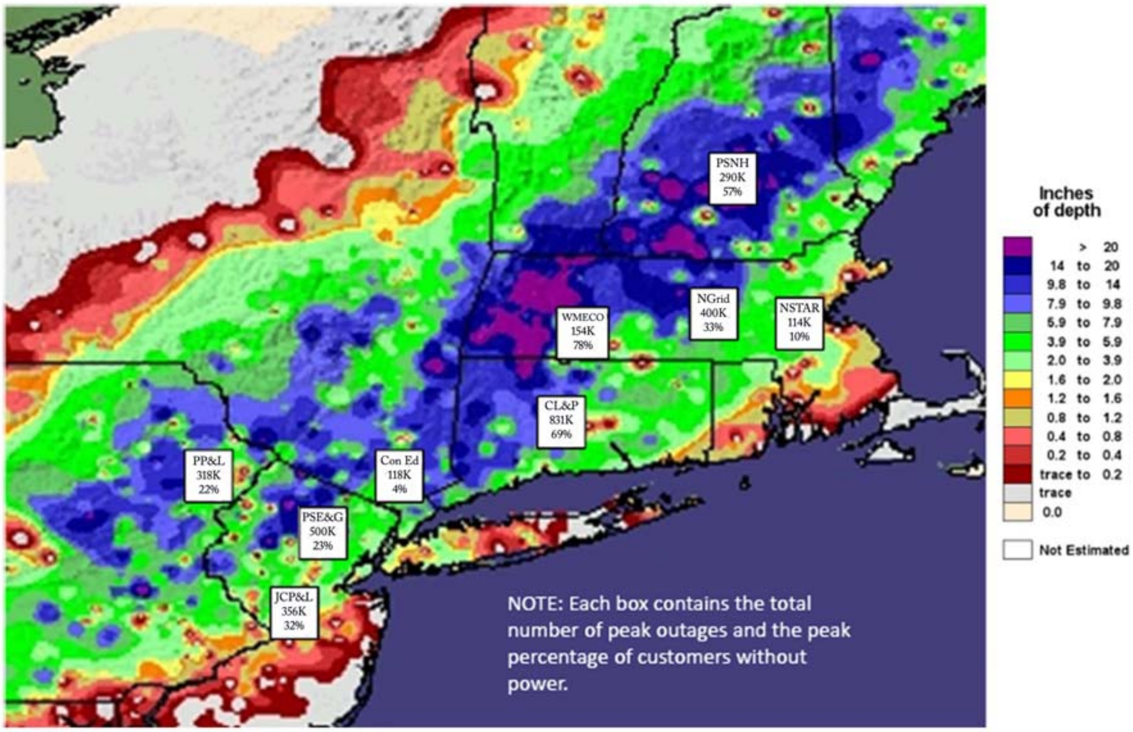

Figure 3: Snowfall Amounts and Customers That Lost Power

Source: NOAA, National Operational Hydrologic Remote Sensing Center, Interactive Snow Information47 and U.S. Department of Energy, Energy Assurance Daily.[48]

There was significantly more damage to distribution facilities than transmission facilities for a number of reasons, including the fact that in some areas there are approximately twenty times more miles of distribution lines than transmission lines.[49] In addition, under typical industry practices, vegetation is generally allowed to grow much closer to distribution lines than transmission lines because there is less risk of flashover[50] between low-voltage distribution lines and nearby trees.

---

[47] *Available at* http://www.nohrsc.nws.gov/interactive/html/map.html?ql=station&zoom=&loc=Latitude%2CLongitude%3B+City%2CST%3B+or+Station+ID&var=snowfall_72_h&dy=2011&dm=10&dd=30&dh=0&incr=+%2B+&snap=1&o9=1&lbl=m&mode=pan&extents=us&min_x=-76.041666666669&min_y=33.741666666667&max_x=-63.450000000002&max_y=43.816666666667&coord_x=-69.745833333336&coord_y=38.779166666667&zbox_n=&zbox_s=&zbox_e=&zbox_w=&metric=0&bgvar=dem&shdvar=shading&palette=1&width=1000&height=800&nw=1000&nh=800&h_o=2&font=0&js=1&uc=0

[48] U.S. Department of Energy, supra note 1.

[49] See About NU, Northeast Utilities, http://www.nu.com/aboutnu/nufacts.asp (listing 4,500 circuit miles of transmission lines and 72,000 pole miles of distribution lines).

[50] Flashover is the spontaneous arcing of electricity from a line to a grounded object like a tree.

A number of state utility commissions and other state government agencies have initiated inquiries into the distribution-level customer outages caused by the storm.[51] In addition, several utilities (and some independent entities) have produced reports on the event that focus on distribution system impacts.[52]

B. Transmission Facility Damage and Customer Impact

Although its impact was not as extensive as the damage to the distribution system, the October snowstorm impacted many transmission facilities. Near the end of the storm, about 130,000 customers across six states lost power as a result of transmission line outages.

1. Transmission Outages

Of the seventy-four transmission lines forced out of service for a sustained period during to the storm, the vast majority (seventy) were 115 kV facilities. One 138 kV and three 345 kV lines also experienced outages.

---

[51] The Connecticut Public Utilities Regulatory Authority (Docket No. 11-09-09), the Massachusetts Department of Public Utilities (Docket No. 11-119), the New Hampshire Public Utilities Commission, and the New York State Public Service Commission (Case No. 11-M-0595) are all conducting inquiries.

[52] *See*, *e.g.*, Central Hudson Gas & Electric Corp., *supra* note 21; Consolidated Edison Company of New York, Inc., Report on Preparation and System Restoration Performance: Nor'easter October 29 through November 3, 2011 (Jan. 5, 2012), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={512EF4A0-EC4C-4204-A527-B047022B6FC3}; Davies Consulting, *supra* note 20; McGee, *supra* note 25; Public Service of New Hampshire, Amp Up and Power On: October Nor'easter 2011 (Nov. 2011), *available at* http://www.hollisnh.org/announce/2011OctoberNor'easterReport.pdf; Western Massachusetts Electric Company's Report to the Department of Public Utilities on Expectations for Electric Distribution Company Performance Regarding Emergency Events (Dec. 20, 2011), *available at* http://www.env.state.ma.us/dpu/docs/electric/11-119/12202011-tech-session.pdf.

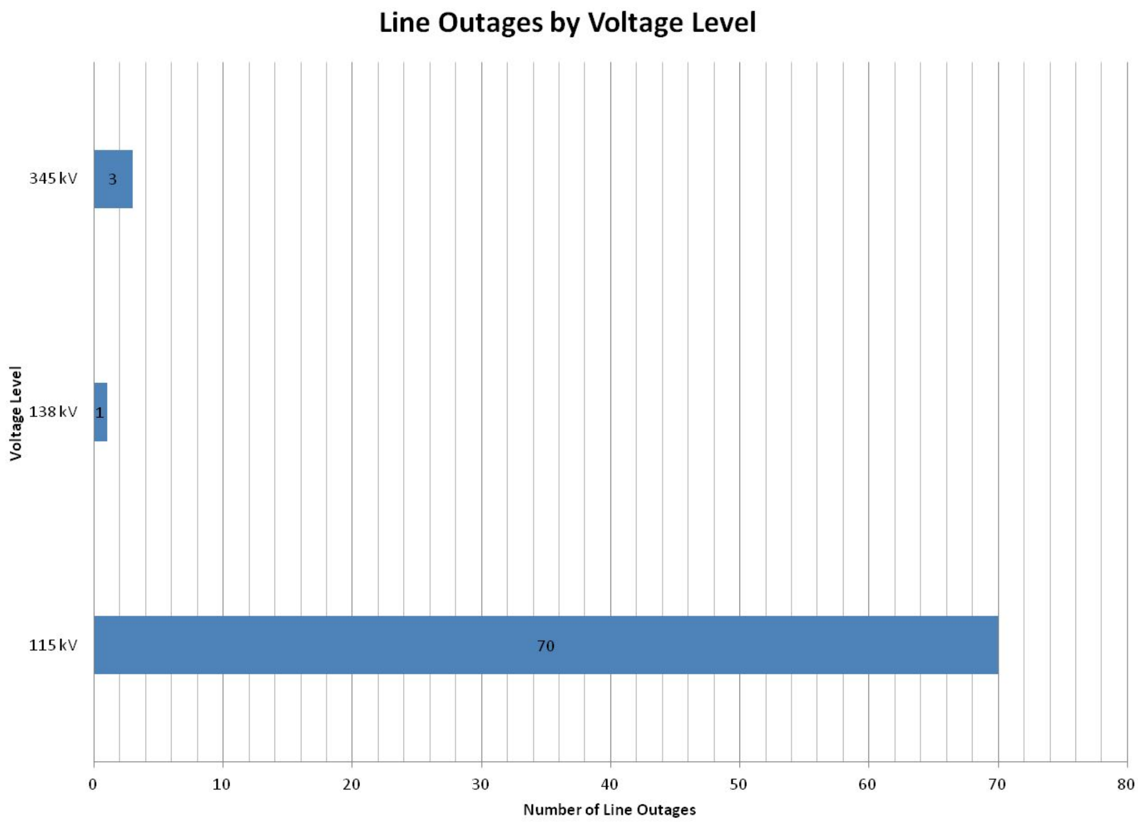

Figure 4: Transmission Line Outages by Voltage Level

There were also seven brief — between one and nine minute — line trips, four of which were caused by relay misoperations.[53]

Twenty-three of these seventy-four line outages occurred on NPCC-designated BPS elements. As explained in footnote 5, NPCC uses a performance-based test to designate facilities as BPS elements.[54]

---

[53] Relay misoperations occur when an automated line monitoring and communications device — a relay — transmits an incorrect signal to a line's breakers, causing the breakers to open when that action is not necessary. Failure of a relay to operate when it should is also considered a misoperation. The one relay misoperation that resulted in a transmission line outage of ten or more minutes is discussed in Section V.C.

[54] NERC has filed, for Commission consideration, a revised definition of BES that would impose a bright-line threshold of 100 kV, such that if approved, all facilities over 100 kV would be part of the Bulk Electric System and subject to most Reliability Standards unless a specific exception was granted or generic inclusion was made. *See N. Am. Elec. Reliability Corp.*, Petition, Docket No. RM 12-06-000 (filed Jan. 25, 2012). This report takes no position on the BES definition filing.

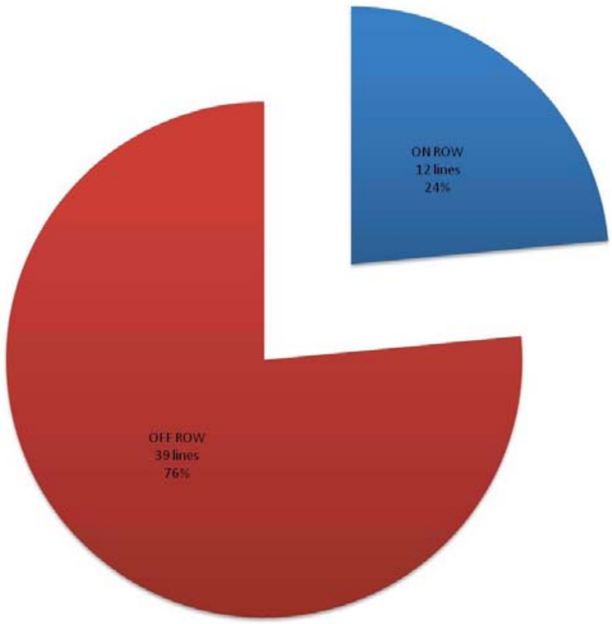

Figure 5: Total Outages: BPS vs. Non-BPS Elements

Because transmission lines conduct power from generating facilities to substations, transmission line outages can cause substation outages.[55] During the October snowstorm, transmission line outages forced forty-four transmission substations out of service, including one NPCC designated as a BPS element. Loss of power to transmission substations is significant for two main reasons. First, many transmission substations provide power to distribution systems, so that the loss of power to a transmission substation can result in thousands of customer outages. Second, transmission substations contain relays and breaker controls that operate to protect individual transmission lines and stabilize the power grid as a whole. When a substation's power source is lost, substation battery banks provide backup power to control equipment and breakers, but those batteries only last for a limited period of time, at which point the equipment can no longer perform its functions. These forty-four transmission substation outages, combined with seventy-four transmission line outages, constituted a significant transmission event.

[55] Sometimes only one transmission line feeds power to a substation. If that single source line experiences an outage, the entire substation will be out of service. Generally, multiple transmission lines provide power to a substation; in that case, the substation will go out of service because of transmission line outages only if all of the transmission lines serving that substation are out of service.

2. Affected States and Utilities

A half-dozen states — Connecticut, Maine, Massachusetts, New Hampshire, New York, and Rhode Island — and ten utilities experienced transmission outages on lines they own, or co-own and maintain. Half of those outages occurred in just one state, Connecticut.[56] The chart below shows the number of outages by state.

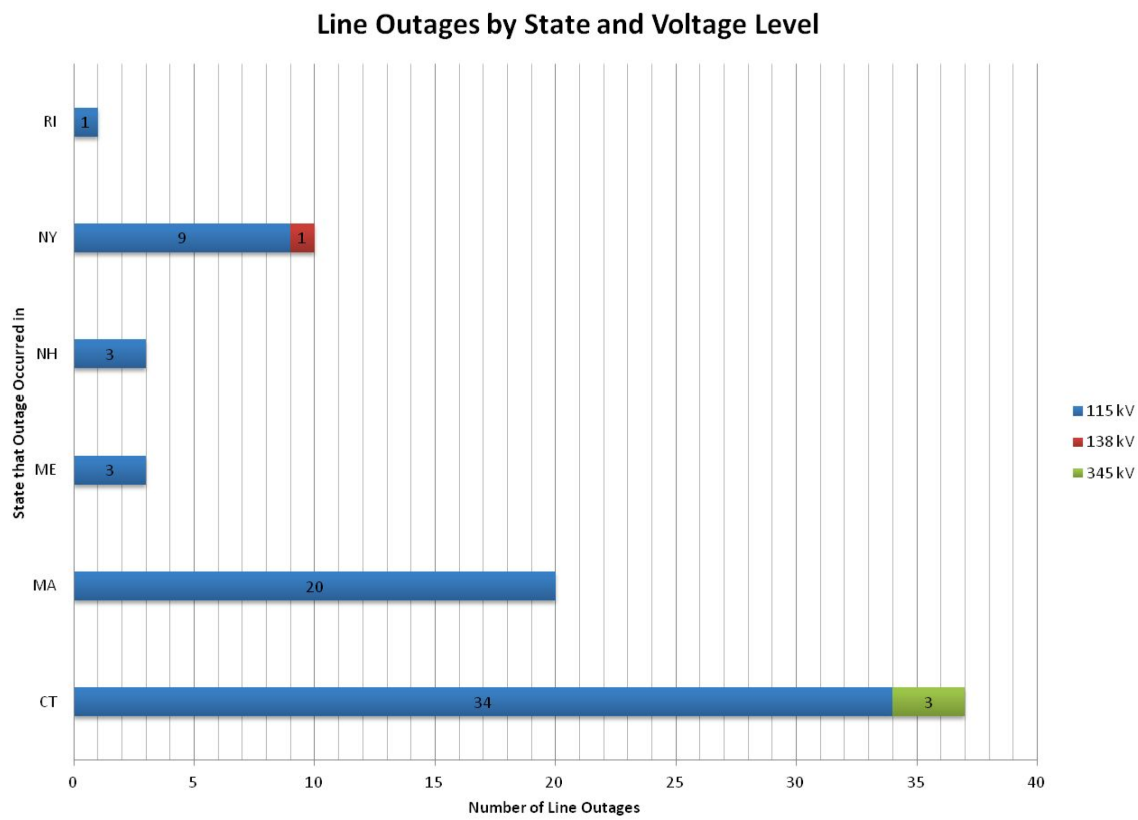

Figure 6: Transmission Line Outages by State and Voltage Level

As the following map shows, transmission line outages were concentrated in the Connecticut River Valley area, through Connecticut and into Massachusetts.

[56] Other states, such as Pennsylvania and New Jersey, experienced significant snowfall and distribution facility outages, but no transmission facility outages.

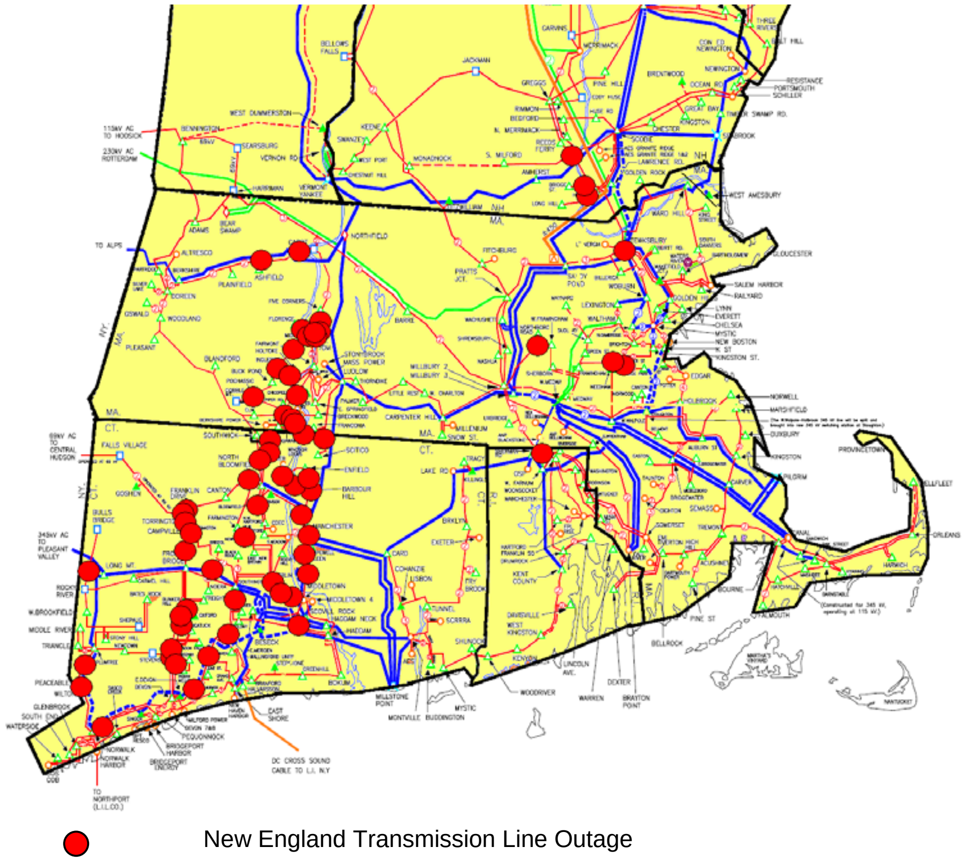

Figure 7: ISO-NE Transmission Line Outages During the October Snowstorm

Source: ISO-New England

The service territories of CL&P and Western Massachusetts Electric Company (WMECO), two subsidiaries of Northeast Utilities (NU), largely cover this area. As shown in the chart below, these two companies had the most transmission line outages. A third NU subsidiary, Public Service of New Hampshire (PSNH), had an additional three transmission line outages. Overall, outages of facilities owned — or co-owned, operated, and maintained — by NU subsidiaries[57] accounted for fifty-four of the October storm's seventy-four transmission line outages (approximately 74%).

---

[57] NU and NSTAR merged on April 10, 2012, and NSTAR is now a subsidiary of NU. Because the merger occurred after the October snowstorm, this report does not include NSTAR as an NU subsidiary.

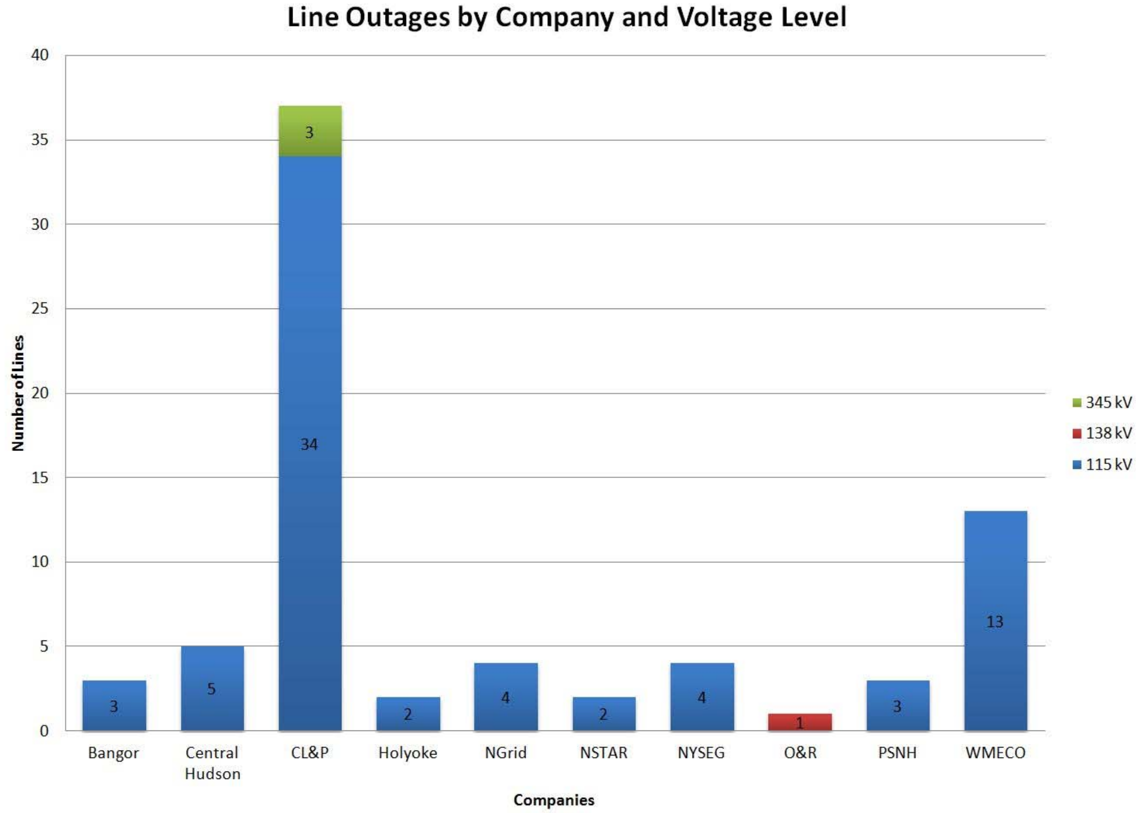

Figure 8: Line Outages by Company and Voltage Level[58]

3. Transmission Facility Outages Had Relatively Limited Impacts on Customers and Were Restored Quickly

Although seventy-four transmission line outages is a significant transmission event, these outages impacted far fewer customers than the distribution facility outages. At the storm's peak, damage to the transmission system caused approximately 130,000 homes and businesses to lose power, less than 5% of all of the storm-related customer outages. In addition, the peak number of transmission-caused customer outages (which rose above 100,000 customers for only about two hours) was relatively small compared to distribution-caused outages. While many customers impacted by distribution facility outages were without service for more than five days – and some for eleven – service was restored to all customers that lost power due to transmission outages in less than five

[58] The full names of the utility companies included in this chart are: Bangor Hydro Electric Co.; Central Hudson Gas & Electric Corp.; Connecticut Light & Power Co.; Holyoke Gas & Electric Department; National Grid USA; NSTAR Electric & Gas Co.; New York State Electric & Gas Co.; Orange & Rockland Utilities, Inc.; Public Service of New Hampshire; and Western Massachusetts Electric Co. Where a line is co-owned by more than one utility, this report attributes the outage to the company with the responsibility for maintaining the line where the outage occurred.

days. In fact, service was restored to the majority (77% percent) of such customers in less than forty-eight hours.

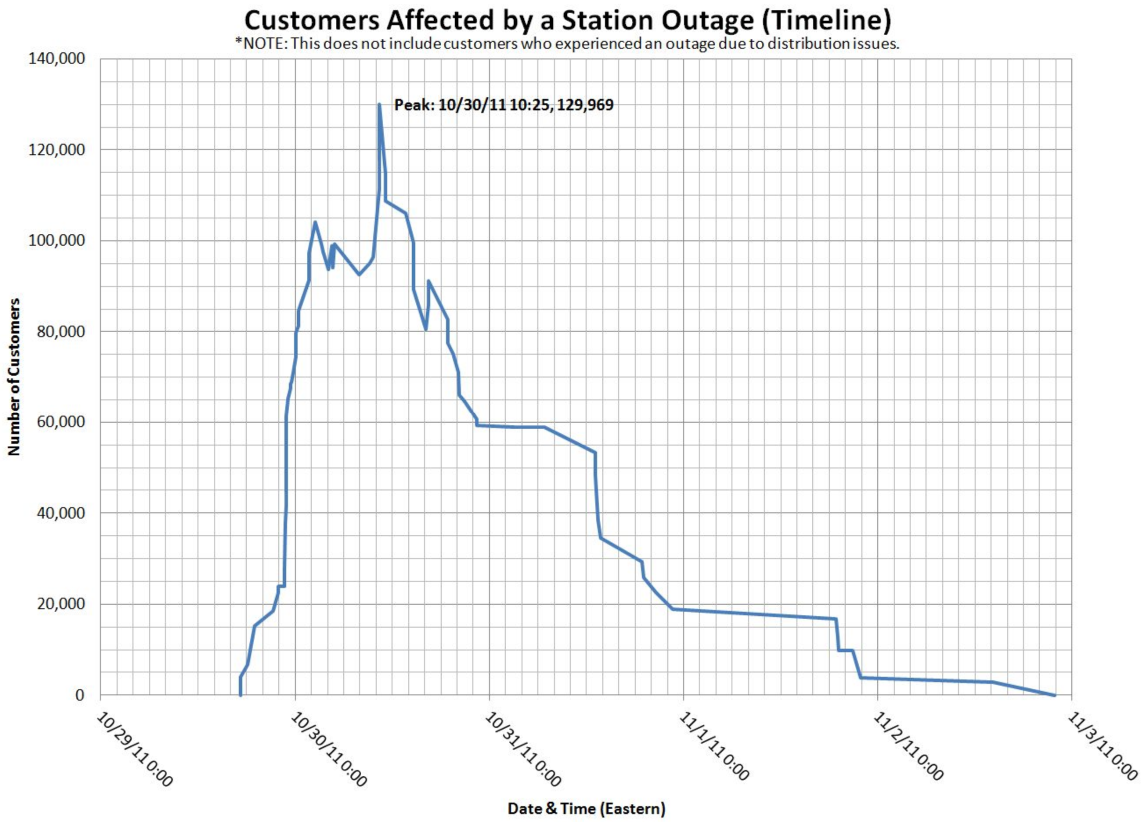

Figure 9: Timeline of Customers Affected by a Transmission Station Outage

While most transmission facilities were restored relatively quickly, four were out of service for nearly a week, and an additional three remained out of service between seven and eight days. However, none of these seven transmission line outages resulted in customer outages or were, at that time, necessary for BPS stability. The following chart illustrates the duration of transmission line outages.

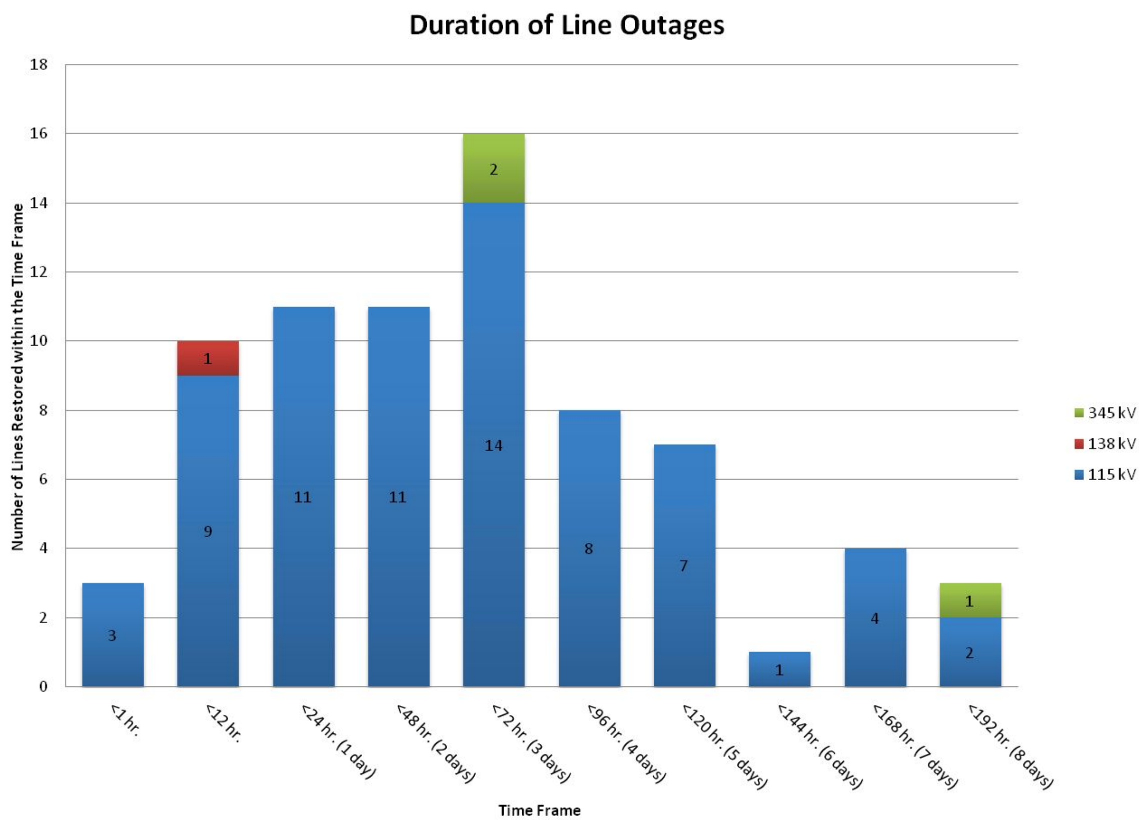

Figure 10: Duration of Transmission Line Outages

Utilities faced several physical obstacles in restoring the seven transmission lines that were out of service for six to eight days. Each of these lines or its supporting structures had significant structural damage that required rebuilding. For example, on five of these seven lines, falling trees snapped insulators, cross-arms, and various support structures. In addition, the site of the damage to the 345 kV line that was out of service for nearly eight days was particularly difficult to access. Again, no retail customers were without service due to these seven line outages.

One of the reasons for fast restoration of many transmission lines that caused customer outages is that, in setting priorities for transmission line restoration, utilities focus on restoration of lines that impact customers and are important for grid stability. For example, NU's restoration priorities for the storm event were: (1) transmission lines that would restore more than one substation; (2) transmission lines that impacted one substation; (3) 345 kV lines; (4) lines that served substations with only one live-line feeding them, such that if the live-line went out of service, the substation — and customers served by it — would experience an outage (i.e., single contingency load loss situations); and (5) all other transmission lines.

Staff concludes that restoration of transmission lines was not materially hampered by inadequate utility preparation or response.[59] For example, staff finds that, overall, additional staffing or field crew pre-staging would not have significantly enhanced transmission facility restoration. However, staff — and utilities themselves — recognize that there is room for improvement in storm preparedness. NU informed staff that its restoration of transmission facilities would have happened somewhat faster, albeit minimally, if the company had obtained more outside assistance in advance of the storm, pre-staged some crews, and had access to additional damage assessment equipment (specifically, helicopters and infrared cameras). Therefore, although utility preparation did not pose significant problems for restoration of transmission facilities during this event, staff recommends in Section IX.4 several steps utilities can take to improve preparation for future severe storm events.

[59] Staff recognizes that a number of states are looking into the impact of utility preparation and response on the distribution system as part of their ongoing proceedings relating to the storm's impacts on customers in their state. This report makes no findings regarding impacts of utility preparation and response on restoration of distribution facilities.

V. Causes of Transmission Facility Outages

As could be expected from a major snowstorm, the vast majority of transmission line outages during the October event were caused by tree contact or the accumulation of ice and heavy, wet snow on transmission conductors.[60] Other causes included losses of source[61] and relay misoperation.

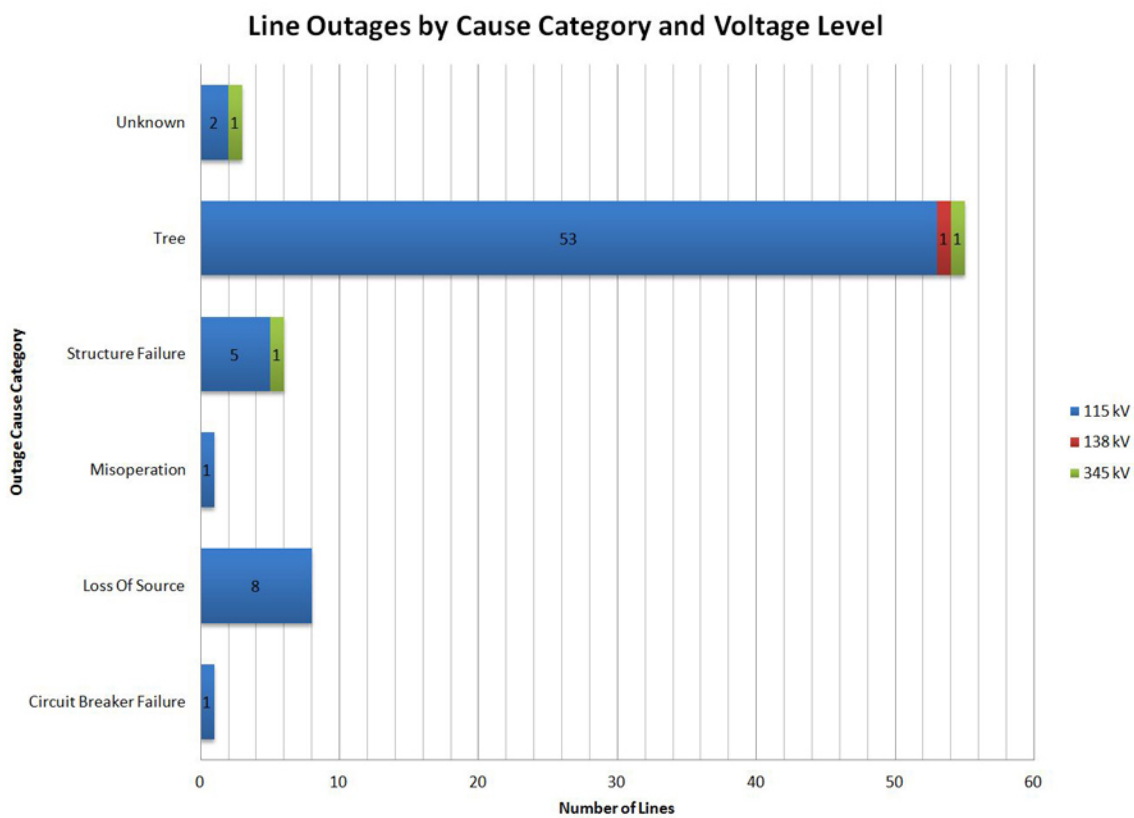

Figure 11: Line Outages by Cause Category and Voltage Level

[60] Transmission lines, the wires that carry electricity, are also called conductors.

[61] "Loss of source" outages occur when a connected line, or series of lines, trip and no longer feed an interconnected transmission line, meaning the interconnected line no longer has a source of electrical energy.

A. Tree Contact

The vast majority of transmission line outages — fifty-five out of seventy-four, or nearly 80% — were caused when snow-weighted leafy trees contacted transmission lines.[62] All but two of these trees were healthy. Twenty-five percent of these trees were located within the utility's right-of-way, and therefore, were likely within the utilities' rights to maintain.

Specifically, thirty-nine transmission line outages resulted from off-right-of-way trees falling onto transmission lines, resulting in loss of power to approximately 84,000 customers. An additional twelve transmission line outages, resulting in 13,000 customer outages, occurred when trees located *inside* a utility's full right-of-way[63] fell into transmission lines. The only tree-caused 345 kV line outage occurred when a sixty-five-foot tall tree located within a full right-of-way (forty-six feet from the nearest transmission line) fell. All of the trees that fell into lines from within the utility's full right-of-way were located outside the area in which the utility performs vegetation management (known as the "maintained right-of-way").[64]

---

[62] Utilities attributed four of those fifty-five outages to tree contact, but post-storm field inspections by the utilities could not definitively confirm that explanation. Based on review of the data, staff accepts the utilities' attribution of these four outages to tree contact.

[63] For purposes of this report, "full right-of-way" means the portion of land for which a utility has documented legal rights to build and maintain transmission facilities.

[64] As explained in Section VII.B, no Reliability Standard requires that utilities manage vegetation on the entire width of their full rights-of-way. In fact, managing a narrower maintained right-of-way, rather than the full right-of-way, is a relatively common industry practice, though not a best practice.

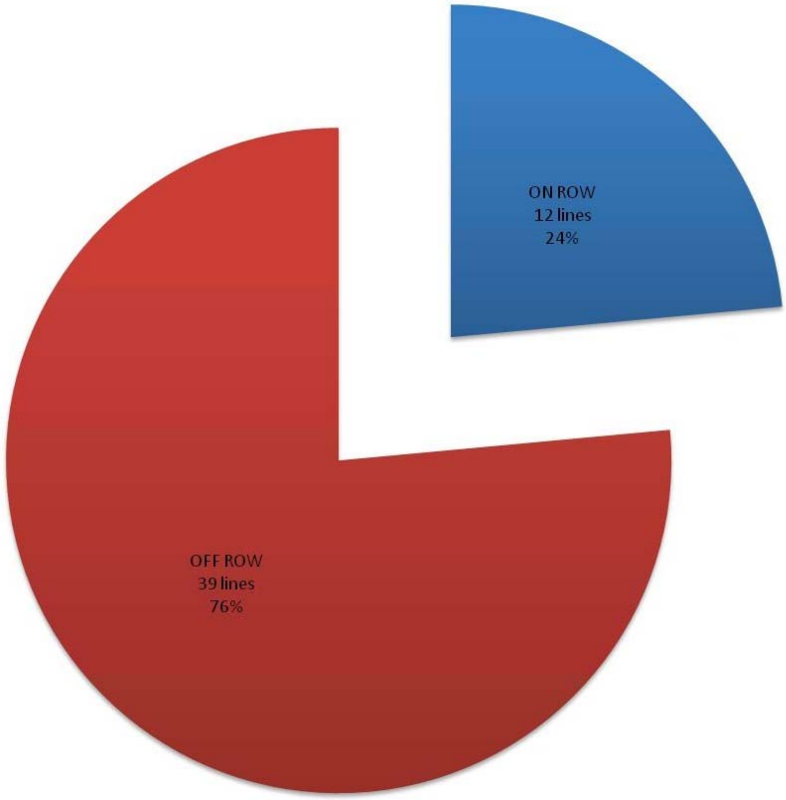

Figure 12: Fallen Trees Located on Rights-of-Way and Off-Rights-of-Way

The 115 kV line in the photograph below was forced out of service when several trees, each over sixty feet tall and located twenty to thirty feet outside of the utility's full right-of-way, uprooted and fell onto three separate spans of the line. Transmission lines are not always located in the middle of a right-of-way, but instead often are closer to an edge of the right-of-way. Thus, as is the case here, a tree may be outside the boundaries of a 130 foot wide right-of-way but still less than sixty-five feet from a conductor.

Figure 13: Trees Fallen on 115kV Line in Connecticut

Source: Northeast Utilities

The line in the photograph below is a 115 kV line in Massachusetts that went out of service when a seventy-five foot tall tree located outside of the 100 foot wide maintained right-of-way, but inside the 200 foot wide full right-of-way, fell onto the line. Because the transmission line was not centered on the right-of-way, the base of the tree, while outside the maintained right-of-way, was only about 30 feet from the nearest conductor.

Figure 14: Tall Tree Fallen on an 115kV line in Massachusetts

Source: Northeast Utilities

As noted above, data obtained during the inquiry indicates that some of the affected utilities only manage vegetation on narrower maintained rights-of-way rather than their full rights-of-way. For example, one utility's maintained right-of-way widths for 115 kV lines range from 68 feet to 280 feet despite having easements of 88 feet to 325 feet. One 345 kV line is located on a 340-foot wide easement, but only 280 feet of the right-of-way is maintained. Staff finds that the removal of danger trees from full rights-of-way could have prevented the twelve 115 kV transmission line outages (six of which were NPCC-designated BPS elements) that resulted from on-right-of-way tree contact during the October Nor'easter. Preventing those line outages would have avoided approximately 13,000 customer outages.[65] Based on the findings outlined above, staff makes several recommendations regarding right-of-way management in Section IX.

[65] Further complicating right-of-way management is the fact that, for a variety of reasons, some utilities find it difficult to locate the exact edges of many rights-of-way in the field.

B. Transmission Structure Failures

Extreme weather conditions caused several transmission facilities to break, resulting in transmission line outages. Temperatures during the snowstorm hovered around 32 degrees, which is conducive to the accumulation of ice and snow on transmission lines. The weight of the accumulated ice and snow on conductors, and, in one case, high wind conditions, caused a number of structures — including static wires,[66] conductors, insulators,[67] and cross-arms[68] — to break, resulting in six transmission line outages and approximately 32,000 customer outages. Although a number of the transmission structures that failed were several decades (or even more than fifty years) old, it does not appear, based on data obtained during the inquiry, that these structures were in need of repair before the storm. Data reviewed by staff also indicates that the affected structures had been maintained according to utility plans, which staff finds are consistent with typical utility practice.

Figure 15: Structure Failure on a 345kV Line in Connecticut

---

[66] Static wire (also known as shield wire) is grounded wire that is strung above conductors to protect them from lightning strikes. The static wire is connected to the grounded tower structure and provides a path for lightning to discharge into the earth.

[67] Transmission line insulators are devices used to contain, separate, or support electrical conductors on high-voltage electricity supply networks. Their purpose is to prevent electricity from arcing between conductors or from conductors to the ground.

[68] Cross-arms are the structures located near the top of transmission poles or metal towers that support conductors.

The 345 kV line shown in the photograph above was forced out of service when the weight of ice and heavy, wet snow on conductors damaged a structure and broke a conductor, static wire, cross-arms, guy-wires,[69] and insulators. This photograph shows (in the background) a wood pole where cross-arms and guy-wires have broken and the conductor has fallen to the ground.

C. Other, or Unknown, Causes

Several transmission line outages were the result of various other, or unknown, causes.

- Eight lines experienced outages as a result of other transmission line failures (i.e., losses of source); these lines were each energized by only one other transmission line, so that when that feeder transmission line failed, the adjacent line also experienced an outage. These loss-of-source transmission line outages caused approximately 16,000 customers to lose power.

- A relay misoperation caused one 115 kV line to be out of service for approximately five hours. As described in footnote 53, a relay misoperation occurs when an automated line monitoring and communications device — a relay — transmits an incorrect signal to a line's breakers, causing the breakers to open when that action is not necessary. In this case, a relay incorrectly detected a problem on the line and forced it out of service. The misoperation did not result in loss of service to any customers.

- One 115 kV line was forced out of service when a circuit breaker component became stuck. The stuck component prevented the breaker from isolating a line that had experienced a fault, resulting in the interconnected 115 kV line losing power. This stuck breaker condition caused about 4,900 customers to lose power for approximately one-and-a-half hours.

- Utility inspections of one 345 kV and two 115 kV transmission lines that experienced outages did not reveal any damage to transmission structures or nearby vegetation, and there is no indication of equipment misoperations. Therefore, the causes of these outages could not be determined by the utility. No customers lost power because of the 345 kV line outage. Approximately 3,800 customers lost service for approximately four to twelve hours as a result of the two 115 kV line outages. Possible causes of those two line outages are undetected tree contacts or arcing across an insulator due to accumulated snow and ice.

[69] A guy-wire is a tensioned cable designed to add stability to structures like utility poles. One end of the cable is attached to the structure and the other is anchored to the ground at a distance from the structure's base.

VI. Transmission Outages Did Not Destabilize the BPS or Regional Systems

Despite the number — and, in some cases, the duration — of the transmission facility outages caused by the storm, the stability of the BPS and the operations of the transmission systems operated by ISO-New England (ISO-NE) and the New York Independent System Operator (NYISO) were never impaired. This was the result of two main factors: a significant decrease in load resulting from distribution facility damage and, to a lesser extent, preventative measures taken by ISO-NE.

A. Bulk Power System Impacts

The loss of seventy-four transmission lines — including twenty-three BPS elements — during the October snowstorm did not strain the BPS. There were no Special Protection System[70] operations. System operators were not required to shed load or take other mitigating measures to maintain reliability. All transmission substations that went out of service were restored before their batteries were depleted; thus, the stability and control of the BPS was not threatened due to those substation outages. In short, the transmission system held up well. An important reason for this, however, is that the damaged distribution system significantly reduced the demands placed on the transmission system. The dramatic drop in power usage (also known as "loss of load") that occurred when millions of customers lost power due to distribution facility damage eased the burden on transmission facilities across the Northeast. Under normal load conditions, seventy-four transmission facility outages could have caused swings in voltage and changes in flows requiring system operators to take emergency actions, possibly including load shedding, in order to prevent cascading outages.[71]

Of course, utilities and regulators strive to prevent loss of load, the effects of which can cause significant harm to customers and the economy. Efforts are currently under way in many Northeastern states to prevent significant damage to distribution systems

[70] Special Protection Systems are systems designed to automatically detect abnormal conditions on a transmission system and to take corrective action. *See* NERC, *supra* note 6.

[71] A cascading outage is a sequence of events where an initial event, or set of events, triggers a series of other outages. Cascading outages can result in widespread power outages, such as those that occurred during the 2003 Blackout. However, in some cases, outages can be halted before the sequence results in a major interruption of electricity service.

in future storms in order to minimize customer outages.[72] If these efforts succeed, then load loss resulting from distribution facility damage during severe weather will diminish, which could then increase the demands on transmission lines during and immediately after storm events. Therefore, while it has always been important that utilities take steps to minimize weather-caused transmission line outages, it becomes especially important to do so as efforts are underway to minimize load loss caused by distribution facility damage.[73]

Although the transmission line outages caused by the October snowstorm did not significantly impact the BPS, future storms could cause greater harm to the BPS, and there are valuable lessons that can be learned from this event. Therefore, staff recommends in Section IX that utilities consider targeted actions to better protect transmission facilities. In particular, as discussed below, staff recommends that, where appropriate, utilities take steps to improve maintenance of their rights-of-way and take a targeted approach to enhance management of off-right-of-way danger trees, focusing on protecting lines rated at 200 kV and above, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System.

B. Regional System Impacts

Transmission facility outages during the storm also had no detrimental impact on the ISO-NE or NYISO operations. The ten transmission line outages in the NYISO74 region did not impact the reliability or operation of the NYISO system: no system operating limits were exceeded, no generation was lost, and all applicable reserve margins were maintained. There was no need for NYISO to implement any emergency procedures or alerts.

---

[72] For example, the Connecticut legislature recently passed a bill that, among other things, requires the state Public Utilities Regulatory Authority to establish standards for electric utilities in preventing outages, restoring power, trimming trees, and for emergency planning, staffing, mutual aid policies, and power restoration coordination efforts with telecommunication companies. SB 23, Reg. Sess. (Conn. 2012).

[73] As during the October snowstorm, future severe storms events that damage transmission lines will also likely damage distribution lines for the simple reason that large-scale tree failures will not occur only, or even primarily, near transmission lines.

[74] NYISO is the independent, non-profit organization that operates New York State's transmission network, administers its wholesale electricity markets, and serves as the state's NERC-certified Reliability Coordinator. A Reliability Coordinator is "[t]he entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System [in a defined area], has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations." NERC, *supra* note 6.

Nearly all transmission facility outages — sixty-four — occurred on the ISO-NE[75] system, but they caused no significant operating impacts. ISO-NE implemented limited procedures to ensure the reliability of the region's transmission system before, during, and after the snowstorm. In anticipation of the snowstorm, ISO-NE implemented an Abnormal Conditions Alert (Master/Local Control Center Procedure 2 (M/LCC-2)) at 1:00 p.m. Eastern Daylight Time (EDT) on Saturday, October 29. This alert protects the stability of the transmission system by requiring market participants to postpone scheduled maintenance, construction, or testing activities in order to maintain reliability in the face of unplanned outages or similar conditions. ISO-NE cancelled the Abnormal Conditions Alert at 11:15 a.m. EDT on Monday, November 7, 2011.

The storm's most significant impact on ISO-NE operations was the significant loss of load caused by the damage to distribution and, to a lesser extent, transmission lines. As a result of the dramatically decreased demand, by Sunday, October 30, ISO-NE had more generation scheduled to run than it needed. In order to reduce the planned power output and keep the system in balance on October 30, ISO-NE twice implemented a Minimum Generation Emergency. This declaration allowed ISO-NE to require generators to operate below the minimum level at which it is economic to run.

Finally, approximately 1,500 MW of generation capacity in ISO-NE went offline during the storm.[76] However, ISO-NE maintained its required reserve margins at all times.[77] All but one of these generation outages were resolved by 9:00 a.m. EDT on October 31. The remaining generator was restored on November 2. The loss of generation capacity had no impact on the stability of the ISO-NE system or the BPS because load levels dropped so significantly during and after the storm that the power the facilities could have produced was not needed.

---

[75] ISO-NE is a private, non-profit organization that operates the transmission grid, administers the energy markets, and serves as the NERC-certified Reliability Coordinator for Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

[76] Twenty-one small units in total were offline; twelve were offline due to loss of transmission lines serving those facilities, seven due to loss of communications for remote start capability, and two due to generator step-up transformer trips.

[77] A generation reserve margin is the amount of generation capacity required to be available at any given time in excess of the amount of generation that is anticipated to be needed to meet actual demand. Reserve margins ensure that there will be enough generation available to meet demand that exceeds projections or to compensate for unanticipated losses of other sources of generation. *See* NERC, *Reliability Indicators: Planning Reserve Margin*, http://www.nerc.com/page.php?cid=4%7C331%7C373.

VII. Applicability of the Transmission Vegetation Management Reliability Standard

As discussed above, the majority of transmission facility outages and related loss of load that occurred during the October snowstorm were the result of vegetation contact with transmission lines. Therefore, the FERC-approved Reliability Standard most relevant to this event is FAC-003-1 (Transmission Vegetation Management Programs). However, its applicability to the October snowstorm event is limited.

A. Overview of Reliability Standard FAC-003-1

Reliability Standard FAC-003-1[78] was developed by the industry with the purpose of preventing outages from vegetation located in transmission rights-of-way and minimizing outages from vegetation adjacent to the right-of-way.[79] The standard requires Transmission Owners to document a transmission vegetation management program (TVMP) that defines a schedule for right-of-way vegetation inspections based on anticipated vegetation growth and other relevant factors.[80] TVMPs must identify two minimum clearances around transmission lines: a "Clearance 2," the minimum distance around transmission lines to be maintained at all times in order to prevent flashover between the lines and vegetation;[81] and a "Clearance 1," the distance around transmission lines utilities will clear to when performing periodic maintenance so as to prevent vegetation from growing into the Clearance 2 space during maintenance intervals.[82] The TVMP also must specify a schedule for, and methods of, vegetation

---

[78] Reliability Standard FAC-003-1 was approved by FERC on March 16, 2007, in Order No. 693, FERC Stats. & Regs. ¶ 31,242, and became mandatory and enforceable on June 18, 2007.

[79] Reliability Standard FAC-003-1 (Transmission Vegetation Management Program), at A.3.

[80] *Id*., at Requirement R1.1.

[81] *Id*., at Requirement R1.2.2. Clearance 2 distances must be at least as great as the clearances set forth in IEEE Standard 516-2003, which range from 0.75 to 6.24 meters (2.45 to 22.44 feet) between conductors and grounded objects like vegetation, depending on the conductor's rating. INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS GUIDE FOR MAINTENANCE METHODS ON ENERGIZED POWER LINES 20, 94 (2003).

[82] Reliability Standard FAC-003-1, at Requirement R1.2. As the Commission explained in Order No. 693, FAC-003-1's clearance requirements mandate that Transmission Owners establish "sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 729. The Commission noted that "all applicable conditions" does not include the extraordinary circumstances specified in Requirement R3.2, which excludes "natural disasters (including wind shears and major storms) that cause vegetation to fall into the transmission lines from outside the [right-of-way]." *Id*.

inspections.[83] In addition, utilities are required to develop annual plans for vegetation management work to ensure reliability, taking into account various factors, such as anticipated vegetation growth.[84] Finally, Transmission Owners must report certain vegetation-related outages to the relevant Regional Entity.[85]

Unlike the vast majority of Reliability Standards, which apply to all BES facilities (i.e., generally, those operated at or above 100 kV, or otherwise as determined by the Regional Entity), FAC-003-1 applies only to BPS "transmission lines operated at 200 kV and above and to any lower voltage lines designated by the [Regional Entity] as critical to the reliability of the electric system."[86] This means that the Standard does not apply to lines operated at voltages under 200 kV in the NPCC region unless NPCC has designated those lines as "critical" under the Standard. NPCC has not designated any transmission lines rated under 200 kV as "critical" for the purposes of applying FAC-003-1.

When approving FAC-003-1, the Commission acknowledged that, although the proposed Standard gave Regional Entities discretion to designate lines under 200 kV to which the Standard would be applicable, no Regional Entity had actually designated any lower-voltage lines as critical for that purpose.[87] The Commission expressed the concern that a bright-line 200 kV threshold for application of the Standard would "exclude a significant number of transmission lines that could impact Bulk Power System reliability."[88] However, in response to industry concerns that, among other things, the costs of expanded applicability to sub-200 kV facilities could outweigh the benefits, the Commission did not require NERC to revise FAC-003-1 immediately. Instead, it directed NERC to "revise it through the Reliability Standards development process, with the expectation that the applicability of this Reliability Standard will expand to include additional facilities that impact reliability that currently are not covered by this Reliability Standard."[89]

---

83 Reliability Standard FAC-003-1, at Requirement R1.

84 *Id.*, at Requirement R2.

85 *Id.*, at Requirement R3.

86 *Id.*, at A.4.

87 Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 706.

88 *Id.*

89 *See id.* P 710.

Because NPCC does not apply FAC-003-1 to any sub-200 kV BPS elements, FAC-003-1 only applied to one line — a 345 kV line in Connecticut — that was forced out of service due to tree contact during the October snowstorm.[90] That line's outage did not result in any customer outages. Thus, although the October snowstorm outages were almost entirely caused by vegetation contact, the Transmission Vegetation Management Reliability Standard applied to only *one* of the fifty-five transmission lines forced out of service by tree contact (and applied to none of the distribution lines damaged in the storm).[91] To the extent that a state does not have vegetation management standards governing transmission lines operated over 100 kV[92] and the relevant Regional Entity has not designated lines operated under 200 kV as critical to the region's reliability for the purpose of applying FAC-003-1, lines operated between 100 kV and 200 kV in that state would not be covered by any federal or state vegetation management standard.

B. FAC-003-1's Scope

If FAC-003-1 had applied to all of the transmission facilities impacted by tree contact during the October snowstorm, compliance with the Standard with respect to those lines may not have prevented the storm's vegetation-caused transmission line outages. This is because: (a) the majority of outages were caused by trees that fell onto transmission lines from outside the utility's right-of-way, and FAC-003-1 does not specifically address off-right-of-way vegetation management; and (b) FAC-003-1 does not dictate specific right-of-way management practices, including how utilities should manage on-right-of-way danger trees.

First, FAC-003-1 does not specifically address management of vegetation located outside a utility's right-of-way. Thus, even if the Standard had applied to all

---

[90] Two other lines that experienced outages during the October snowstorm are operated at over 200 kV, and therefore subject to FAC-003-1, but those outages were not caused by vegetation contact.

[91] On December 21, 2011, NERC filed with FERC a proposal to replace FAC-003-1 with a new standard, FAC-003-2. Among other things, FAC-003-2 would revise the Standard so that it would be applicable to all transmission lines operated at or above 200 kV and any line that is an element of an Interconnection Reliability Operating Limit (IROL) or a Western Electric Coordinating Council (WECC) Transfer Path. N. Am. Elec. Reliability Corp., Petition, Docket No. RM12-4-000 (filed Dec. 21, 2011). However, this expanded applicability would not have significantly increased the Standard's impact on lines forced out of service by tree contact during the October snowstorm because only eight of those 115 kV or 138 kV lines are IROL elements (none are WECC Transfer Paths). Moreover, the proposed FAC-003-2's requirement that no vegetation come into contact with lines governed by the Standard does not apply when the vegetation contact is caused by major storms. This report does not offer any views on proposed FAC-003-2, which is currently under review by the Commission.

[92] *See, e.g.*, N.Y. Comp. Codes R. & Regs. Title. 16 §§ 84.2, 84.3; Cal. Gen. Order 95, Rule 35.

transmission lines impacted by vegetation during the October storm, it would not have addressed the condition — tall trees growing outside of utilities' rights-of-way — that caused over half of all storm-related outages. One reason FAC-003-1 does not explicitly address off-right-of-way vegetation management is that land adjacent to rights-of-way is typically not owned by the utility, and state laws usually limit utilities' ability to prune or remove trees on property they do not own. Although state laws differ, generally speaking, a utility may not remove a tree (including a danger tree) located outside of its right-of-way without the property owner's consent.[93] Moreover, obtaining permission to remove off-right-of-way trees can be complicated and difficult.

When utilities and state agencies set policies and make decisions regarding removal of danger trees outside the right-of-way, they must consider a number of factors. Reliability of the transmission system, and, in particular, preserving the stability of the BPS, is a central concern. However, environmental issues, property rights, viewsheds, and cost also play an important role. In heavily forested regions like New England, even if possible, the reliability benefits of removing all danger trees from outside utilities' rights-of-way often would not outweigh the costs of doing so.[94] For example, Northeast Utilities provided staff with an estimate that there are some 800,000 danger trees along the edges of its rights-of-way, and that removing them would cost approximately $400 million.[95] Notwithstanding competing policy concerns, off-right-of-way tree fall-ins were the leading cause of transmission line outages during the October snowstorm, and, in general, some off-right-of-way danger trees can pose a threat to reliability. Therefore, staff makes a recommendation in Section IX that utilities should re-evaluate, and work to enhance, their off-right-of-way vegetation management.

---

[93] *See, e.g.*, N.H. Rev. Stat. Ann. § 231:172(I) (electric utilities must obtain consent of the landowner to prune trees outside of the right-of-way); *see also Tree Trimming FAQs*, PUBLIC SERVICE OF NEW HAMPSHIRE, http://www.psnh.com/CustomerSupport/Home/Tree-Trimming-FAQs.aspx (explaining procedures for obtaining consent of tree owners before performing trimming maintenance). In some circumstances, if a utility provides notice of its intent to remove a tree and the landowner does not object, the utility may proceed without specific permission. *See, e.g.*, N.H. Rev. Stat. Ann. § 231:172(II)(b) (stating that the utility may perform the work without permission if the tree owner does not request personal consultation after receiving notice). In some states, there are expedited procedures for obtaining permission to remove "hazard trees" — trees that present an imminent danger to transmission lines because they are damaged or diseased. *See, e.g.*, Mass. Gen. Laws Ann. ch. 87 § 14(b), (c) (permitting electric utilities to file hazard tree removal plans for approval by the tree warden to avoid otherwise applicable restrictions on tree removal).

[94] As ISO-NE has stated, "[t]he political, social and environmental expectations placed on utilities in New England prevent the clearing required to guarantee total system protection from falling trees. In severe weather events (hurricanes, micro bursts, tornadoes and ice storms) trees may fail and fall into lines." ISO-NE, OPERATING PROCEDURE 3 Appendix C (2005).

[95] Of course, the monetary and non-monetary costs of danger tree removal must be weighed against, among other things, the often high costs of transmission outages.

Second, while FAC-003-1 does require utilities to maintain plans and procedures to address vegetation to meet its Clearance 1 requirements, and utilities have considerable flexibility in designing transmission vegetation management programs as long as utilities are compliant with the FAC-003-1 requirements, the Standard does not specifically dictate how utilities should manage danger trees that are outside of Clearance 1 but within the right-of-way. Thus, utilities may maintain vegetation clearances on less than the full right-of-way, which can increase the number of danger trees within the right-of-way. [96]

FAC-003-1 does recognize that the American National Standard Institute's (ANSI) Standard A300, which provides guidelines for integrated vegetation management on electric utility rights-of-way,[97] is an industry best practice.[98] ANSI A300 does not specifically prohibit growth of danger trees on a right-of-way, but it does explain that the "wire zone-border zone" vegetation management method, where the full right-of-way is managed in order to prevent the growth of danger trees, "is a proven method that ensures the reliability of electric supply lines."[99] The wire zone-border zone method allows very low-growing vegetation such as grasses and other groundcover species in the area under and immediately around transmission structures (the "wire zone") and permits short-growing vegetation like shrubs and short trees from the outer edge of the wire zone to the edge of the utility's full right-of-way (the "border zone").[100] The following drawing illustrates the wire zone-border zone concept.

---

[96] Staff notes that no registered entity has been charged with a violation of FAC-003-1 as the result of a healthy tree falling onto (as opposed to growing into) a transmission line.

[97] Integrated vegetation management (IVM) is "[a] system of managing plant communities in which compatible and incompatible vegetation is identified, action thresholds are considered, control methods are evaluated, and selected control(s) are implemented to achieve a specific objective." ANSI A300, *supra* note 14 at 72.

[98] Reliability Standard FAC-003-1, at Requirement R1 n.1.

[99] ANSI A300, *supra* note 14 at 75.2, Annex A.

[100] ANSI A300, *supra* note 14; RANDALL H. MILLER, BEST MANAGEMENT PRACTICES: INTEGRATED VEGETATION MANAGEMENT 17 (2007) (companion publication to ANSI A300).

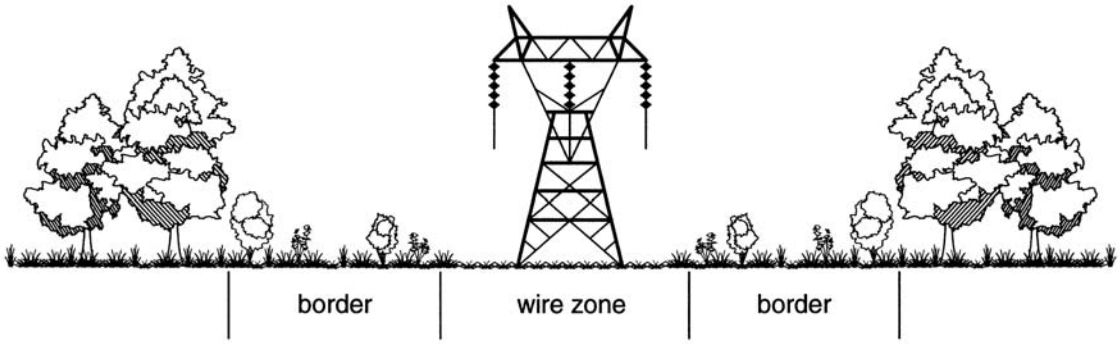

Figure 16: Wire Zone-Border Zone Illustration

Source: UVM Final Report, infra note 109

FAC-003-1's focus on maintaining clearances through a specific method like the recognized wire zone-border zone best practice reflects an emphasis on preventing vegetation from growing or swaying into conductors (or conductors swaying or sagging into vegetation) rather than vegetation breaking and falling into conductors, especially during severe storms.[101] Thus, to minimize the damage caused by similar events in the future vegetation management requirements would need to include a requirement to address at least those danger trees growing within the right-of-way.

[101] Indeed, the genesis of FAC-003-1 was the major blackout that occurred on August 14, 2003, which was caused in significant part by unmanaged vegetation that, due to growth and line sag, contacted several 345 kV lines and precipitated cascading outages throughout the eastern United States and Canada. *See* U.S.-CANADA POWER SYSTEM OUTAGE TASK FORCE, *supra* note 12. Proposed FAC-003-2 requires that Transmission Owners manage vegetation in order to prevent *any* vegetation from making contact with transmission lines – including fall-ins. *N. Am. Elec. Reliability Corp.*, Petition, Docket No. RM12-4-000, at Proposed Standard FAC-003-2, R1, R2 (filed Dec. 21, 2011). However, as stated in note 91, the proposed standard would *not* apply to vegetation contact in "circumstances that are beyond the control of a Transmission Owner," including natural disasters such as "major storms as defined either by the Transmission Owner or an applicable regulatory body . . . ." *Id.*, at R1 n.2. As previously noted, this report takes no position on proposed FAC-003-2.

VIII. Outage Reporting Provides Limited Information

During and after the storm, two Reliability Standards – FAC-003-1 and EOP-004-1 – required that entities report some information about their outages to either NERC or NPCC. However, those requirements, and the responses provided by most affected utilities, resulted in FERC and NERC initially receiving limited information about the event. Based on the findings in this Section, staff makes recommendations in Section IX for improved or enhanced reporting of certain outage information.[102]

Standard FAC-003-1 requires Transmission Owners to report on a quarterly basis to Regional Entities such as NPCC sustained vegetation-caused outages on lines subject to that Standard,[103] and NPCC guidance also instructs transmission owners to report vegetation-caused outages on any BPS elements operated under 200 kV.[104] However, outages caused by off-right-of-way tree contacts during natural disasters, including major storms, do not have to be reported under FAC-003-1.[105] While NERC obtains certain data about outages through other reporting mechanisms, there are no data reporting requirements in place that mandate the reporting of all the transmission facility outages that occurred in the October storm. Nor were all such outages, in fact, reported to NERC. Thus, utilities were not required by FAC-003-1 to submit information on the October storm's BPS element outages caused by off-right-of-way tree fall-ins.

Staff gathered substantial information about these outages during the inquiry, but is concerned that information about off-right-of-way tree fall-ins during other weather

[102] This report's findings and recommendations regarding reporting address only issues related to reporting outage information to FERC, NERC, or the Department of Energy (DOE). We do not address issues related to reporting distribution facility or customer outages to state regulators. However, staff notes that there have been calls to improve the consistency of distribution facility outage reporting. *See* MASSACHUSETTS INSTITUTE OF TECHNOLOGY, *The Future of the Electric Grid*, 9 (2011), *available at* http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml ("Most outages occur within distribution systems, but only 35 U.S. states require utilities to report data on the impact of all outages on consumers, and reporting standards and practices differ. It is accordingly impossible to make comprehensive comparisons across space or over time.").

[103] Reliability Standard FAC-003-1, at Requirement R3.

[104] NPCC, COMPLIANCE GUIDANCE STATEMENT ON REPORTING OF TRANSMISSION OUTAGE RELATED TO VEGETATION CONTACT (rev. Oct. 3, 2008), *available at* https://www.npcc.org/Compliance/Compliance%20Guidance%20Statements/Forms/Public%20List.aspx.

[105] Reliability Standard FAC-003-1, at Requirement R3.2.

events may not be reported. The weather exception prevents regulators from obtaining a key source of information about the extent and severity of these types of outages. Better information would allow policymakers to understand the scope and impacts of weather-caused off-right-of-way tree fall-ins, and to assess whether regulations or guidance should be formulated to address those outages.

Second, staff finds that, during and after the October snowstorm, affected entities did not always provide thorough information in the disturbance reports they were required to file with NERC under Reliability Standard EOP-004-1. That Standard mandates that registered entities submit completed disturbance report forms — either the DOE Electric Emergency Incident and Disturbance Report (Form OE-417) or NERC's Interconnection Reliability Operating Limit and Preliminary Disturbance Report — after certain events, including those where there is significant loss of load.[106] Initial Form OE-417s must be submitted to DOE and NERC within an hour of the disruption, and, at the time of the October storm, final reports providing complete disruption information were required to be filed within 48 hours of the event.[107] However, the majority of the OE-417 forms submitted by utilities during and after the October snowstorm did not provide enough information to allow for a useful initial analysis of the event. For example, many final reports did not include full narrative descriptions of events, or include the voltage of transmission lines that experienced outages. This lack of thoroughness, particularly in the final reports, made it difficult for FERC and NERC staff to ascertain the exact nature of the impact of the storm on the affected systems.[108]

---

[106] Reliability Standard EOP-004-1 (Disturbance Reporting), at Requirement R3.

[107] *Id.*, Attachment 2. As of January 1, 2012, the forty-eight-hour reporting requirement for final reports was extended to seventy-two hours.

[108] The inconsistency and incompleteness of information regarding BPS outages was also noted in the MIT report on the future of the electric grid: "At the bulk power level, data on major disturbances and unusual occurrences have been reported to the U.S. Department of Energy (DOE) since the 1970s and to the North American Electric Reliability Corporation (NERC), which has responsibility for the reliability of the bulk power system, since 1984. However, these data are not consistent, complete, or necessarily accurate, and they cannot reliably be used to assess changes in the reliability of the bulk power system over time." *See* MASSACHUSETTS INSTITUTE OF TECHNOLOGY, *supra* note 102, at 9.

IX. Recommendations

The October 2011 Nor'easter was a rare storm that, due to a number of circumstances — record amounts of heavy wet snow, trees that had not lost most of their leaves, and unusually saturated ground — had severe and widespread impacts on the electricity infrastructure in the Northeast. Staff recognizes the unusual aspects of this weather event. Nonetheless, based on information gathered and findings made during the inquiry, staff concludes there are a number of "lessons learned" that, if implemented, could improve reliability during future storms and similar weather events. Accordingly, staff makes the following recommendations with regard to transmission facilities.

• ***Vegetation Management Recommendations***[109]

By far, the leading cause of transmission line outages during the October snowstorm was trees or tree branches falling onto power lines from outside and inside utilities' rights-of-way.[110] Staff therefore recommends that utilities take the following targeted steps to enhance their management of danger trees both on and off their rights-of-way in order to reduce these types of outages.[111]

1. Where Appropriate, Utilities Should Take Targeted Steps to Address Off-Right-of-Way Danger Trees

As noted above, off-right-of-way tree fall-ins accounted for about half of the storm's transmission line outages, and nearly 75% of all confirmed vegetation-caused outages. Off-right-of-way danger trees are a particular threat to reliability in New England, where there may be hundreds of danger trees along one span of a transmission line. Staff

[109] In response to the 2003 Blackout, FERC commissioned a separate vegetation management report to support the federal investigation into that event. The result was the Utility Vegetation Management Final Report, completed by CN Utility Consulting, LLC and published in 2004. STEPHEN R. CIESLEWICZ & ROBERT R. NOVEMBRI, UTILITY VEGETATION MANAGEMENT FINAL REPORT (March 2004) [hereinafter "UVM Final Report"], *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/uvm-final-report.pdf. The recommendations related to vegetation management in this report are similar to several of the vegetation management recommendations made in the UVM Final Report.

[110] In fact, the majority of vegetation-related outages in the United States are caused by trees or portions of trees falling into lines from distances outside of normal clearing zones (i.e., Clearance 1 or Clearance 2 distances). *See* NERC, *Vegetation Management Reports*, http://www.nerc.com/page.php?cid=3|26.

[111] Staff recognizes the sensitivity of vegetation management issues and the difficulty of expanding rights-of-way and more effectively maintaining them. However, these difficulties must be balanced against the reliability and safety benefits of improved right-of-way management.

recognizes that in most cases utilities are not free to unilaterally remove off-right-of-way trees, that the process for obtaining permission to do so is frequently difficult and costly, and that tree removal often faces significant landowner and public opposition. Moreover, the costs of indiscriminate, widespread removal of off-right-of-way danger trees may outweigh the reliability benefits of doing so.

Taking all these factors into consideration, staff recommends that, where appropriate, utilities follow a targeted approach to enhancing their off-right-of-way danger tree management, focusing on protecting lines operated at 200 kV and above, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System. Utilities should analyze their transmission systems in order to identify danger trees — particularly those species of trees that have a tendency to fail — that could impact critical transmission lines. After performing this analysis, utilities should work with affected property owners, state regulators, and local communities to develop a strategy for managing those trees that pose the greatest threat to those facilities. In addition, if state laws or policies significantly impact utilities' ability to manage off-right-of-way danger trees that could impact these critical facilities, utilities should work with stakeholders and state and local governments to develop solutions that reduce risk to those lines.

2. Utilities Should Employ Recognized Best Practices in Managing Rights-of-Way Where Feasible

Staff found in Section V.A that roughly 25% of the confirmed vegetation-related transmission line outages during the October event were caused by trees that fell into transmission lines from inside a utility's full right-of-way. These on-right-of-way trees were all located outside the utility's maintained right-of-way. Based on this finding, staff recommends that, where possible and practical, utilities implement the industry best practice of ensuring that danger trees are not present within their full rights-of-way.[112] In particular, to the extent a utility manages vegetation only on maintained rights-of-way rather than full rights-of-way, it should work toward reclaiming the full right-of-way width where feasible.[113]

[112] Staff recognizes that there are a number of ways to achieve this result. The wire zone-border zone right-of-way maintenance method, discussed in Section VI, is recognized as highly effective in protecting against on-right-of-way tree contact and generally maintaining reliability. Selection of the most appropriate maintenance method for any given right-of-way should be made by qualified vegetation management personnel.

[113] Maintaining narrower areas within a full right-of-way is not an uncommon practice in the industry and occurs for a variety of reasons, some of which are outside the control of the utility. However, it is not a best practice.

Two key components of reclaiming and maintaining full rights-of-way are (1) knowing the exact boundaries of that area and (2) being able to identify those boundaries in the field. This is not always easy, given that traditional markers (such as wooden stakes or iron plates) can deteriorate or get lost during four-plus year vegetation management cycles. However, technologies such as Light Detection and Ranging (LiDAR) and Global Positioning Systems (GPS) can help utilities accurately and more permanently identify right-of-way boundaries on the ground. Staff recommends that, over time, utilities work toward employing technologies that will allow them to track the exact boundaries of all of their transmission rights-of-way and locate those boundaries in the field.

Staff recognizes there are a number of circumstances where utilities may be unable to completely prevent the presence of danger trees within full, or even maintained, rights-of-way through implementation of the wire zone-border zone management or other, similar techniques, and that utilities have been, and must continue to be mindful, of these circumstances.[114] For example, utilities may be prohibited by state law from removing certain vegetation on their rights-of-way in environmentally sensitive areas, or may be required to maintain on-right-of-way vegetation in order to partially shield power lines from view.[115] Removal of danger trees also may not be possible where the easement establishing the utility's right-of-way explicitly limits, or does not clearly permit, vegetation management in the full easement area. Even where the easement gives a utility rights to manage vegetation across the entire right-of-way, past practices (for example, years of permitting landowners to grow tall trees inside the right-of-way), landowner objections, or public sentiment opposing the maintenance of wide rights-of-way may make it difficult to employ the wire zone-border zone method or otherwise to remove danger trees. Staff also recognizes that reclaiming rights-of-way that are not currently being fully managed can be expensive, time consuming, and difficult. However, staff finds that consistently maintaining the full right-of-way would reduce the number of danger trees near transmission lines.[116]

---

[114] *See, e.g.,* CIESLEWICZ & NOVEMBRI, *supra* note 109, at 21 (recognizing that there are locations where implementing the wire zone-border zone model is not practical); MILLER, *supra* note 100, at 18-19 (same).

[115] *See generally*, CIESLEWICZ & NOVEMBRI, *supra* note 109, at 15-16.

[116] Staff recognizes that, in some instances, removing certain tall-growing trees from the interior edge of the full-right-of-way may expose weaker, top-heavy danger trees on the exterior edge, posing more of a risk of a tree falling into the transmission facilities.

Utilities should, of course, take these circumstances into account when evaluating their right-of-way management policies to specifically address danger trees. Staff recommends that utilities: (a) identify the areas where elimination of danger trees inside the full right-of-way is possible given site-specific circumstances and (b) evaluate whether danger tree removal/right-of-way reclamation would increase reliability and be feasible. Once rights-of-way that are appropriate for removing danger trees are identified, utilities should prioritize their efforts, focusing first on rights-of-way surrounding lines that are rated at or above 200 kV, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System.

In sum, in order to improve reliability during future major storms, staff recommends that, where possible, utilities develop and implement plans to ensure that danger trees are not located within their full rights-of-way.[117]

3. Utilities Should Lay the Foundation for Effective Vegetation Management When Establishing New Rights-of-Way

Preventing fall-ins from both inside and outside the right-of-way is easier if utilities consider vegetation management needs when siting new transmission lines and acquiring new easements. Therefore, staff recommends that utilities carefully assess vegetation and growth rates in the area of planned lines in order to establish the appropriate right-of-way width. For example, if native trees have a mature height of 100 feet, the easement should cover an area wide enough to ensure that existing and future trees outside of the right-of-way will not fall into the facilities.[118]

In addition, utilities should ensure that easement documents protect the utility's ability to ensure safe and reliable transmission of electricity. New easements should clearly provide the utility with rights to manage the full easement in order to prevent the presence of danger trees inside the right-of-way. In addition and where possible, new easements should give the utility the ability to remove danger trees outside of the right-of-way.

---

[117] To be clear, preventing the presence of danger trees within the right-of-way does *not* mean that full rights-of-way need to be (or should be) clear-cut. This recommendation is focused on ensuring that, where feasible, danger trees – those trees that could fall into a transmission line or structure – are not present within rights-of-way because they can threaten reliability. Many types of trees growing within rights-of-way do not constitute danger trees.

[118] *See* CIESLEWICZ & NOVEMBRI, *supra* note 109, at 71.

• Other Recommendations

4. Utilities Should Evaluate and, As Needed, Enhance Their Storm Preparedness and Response Plans

As explained in Section III, the October snowstorm exceeded forecasts, and many utilities scrambled — often at the last minute — to assemble adequate response personnel, especially field crews. Although these manpower and related issues did not significantly hinder restoration of transmission line outages or unduly prolong transmission-caused customer outages, the event revealed potential areas of improvement in preparation for future storms. Thus, staff recommends that utilities evaluate their severe storm preparation and response plans to ensure they are flexible and scalable enough to quickly respond to events that are more severe than predicted. For example, utilities should: (a) clearly define how and when they will request outside assistance, through mutual aid or outside contractors; (b) be prepared for regional mutual assistance crews to be unavailable when a weather event is predicted to impact many states, either by requesting mutual aid from other regions early on or retaining additional local contractors to make up for the lack of immediately available mutual assistance; (c) have a policy in place regarding if, when, and where pre-staging will occur; (d) have the ability to, and procedures regarding, reservation of equipment, such as helicopters and infrared cameras, in advance of major storms in order to ensure prompt assessment of transmission system damage; and (e) in regions where extreme weather events occur, and especially where they are becoming more common, retain experienced weather personnel with the responsibility to predict likely impacts of weather events, taking into account service-territory-specific conditions.

5. Utilities Should Report All Vegetation-Caused BES Facility Outages to NERC

As discussed in Section VIII, even though off-right-of-way tree contact during severe storms is a frequent cause of transmission line outages, FAC-003-1 does not require utilities to report those outages to Regional Entities or NERC. Moreover, the Standard does not require the reporting of vegetation-caused sustained outages on BES transmission lines not subject to FAC-003-1 (i.e., those operated at voltages below 200 kV or lower-voltage lines not designated as critical by a Regional Entity). To ensure that regulators have sufficient information to allow them to make informed policy decisions about these types of outages, staff recommends that all tree contact-caused BES facility outages be reported to NERC.

6. Disturbance Reports Should Be Clear and Complete

Section VIII finds that although a number of entities were required by Reliability Standard EOP-004-1 to file preliminary and final disturbance reports related to the October snowstorm outages, many of the filed forms were not completed thoroughly. This lack of thoroughness made it difficult to quickly ascertain the impact of the storm on the affected systems. Staff recommends that, where possible, all entities required to file disturbance reports under EOP-004-1 promptly provide thorough, descriptive, high-quality information in the initial reports as it becomes available to them. With regard to the final disturbance reports, utilities should ensure their responses are comprehensive, providing all the relevant information in their possession.

ATTACHMENT 2

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

4.2.1. 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 Coordinator.

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

---

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

[2] *Id.*

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do 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 Coordinator; 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 <u>performance result or outcome</u>?*

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 <u>reduces a stated risk</u> 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 <u>what capability</u>, 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.

---

[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.

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

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

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, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

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. 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 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; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

---

[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.

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 the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

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. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner 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]*:

2.1. An encroachment into the MVCD, 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 the 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]

---

[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.*

[8] *Id.*

[9] See footnote 4.

[10] See footnote 5.

[11] See footnote 6.

[12] *Id.*

[13] *Id.*

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. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

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. The maintenance strategies or procedures or processes or specifications provided demonstrate 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 the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

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. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management 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. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[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. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner 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*]:

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

---

[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.

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"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	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of

			an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	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*
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	The responsible entity experienced a confirmed

			vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	vegetation threat and did not notify the control center holding switching authority 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

- 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

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

2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
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 became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became 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	February 11, 2016	Adopted by Board of Trustees. 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
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	

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 feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
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	14.1ft	14.3ft
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	8.9ft	9.1ft
345	362[19]	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	5.7ft
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	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	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
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	3.7ft	3.8ft
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	3.2ft
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	2.7ft
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	2.2ft	2.2ft
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	1.6ft	1.6ft

* Such lines are applicable to this standard only if PC 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 EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

[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.

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268m up to 4572m
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	4.3m	4.4m
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	2.7m	2.7m
345	362[22]	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	1.7m	1.8m
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	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	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	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	1.0m	1.0m
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	0.8m	0.8m
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	0.7m	0.7m
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	0.5m

* Such lines are applicable to this standard only if PC 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 EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

---

[20] 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.

[21] 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.

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

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)

[23] 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 Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 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 later 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 Inspection:
The current glossary definition of this NERC term was 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 equation. 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 of the Standard 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.

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 was comprised of 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.

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.

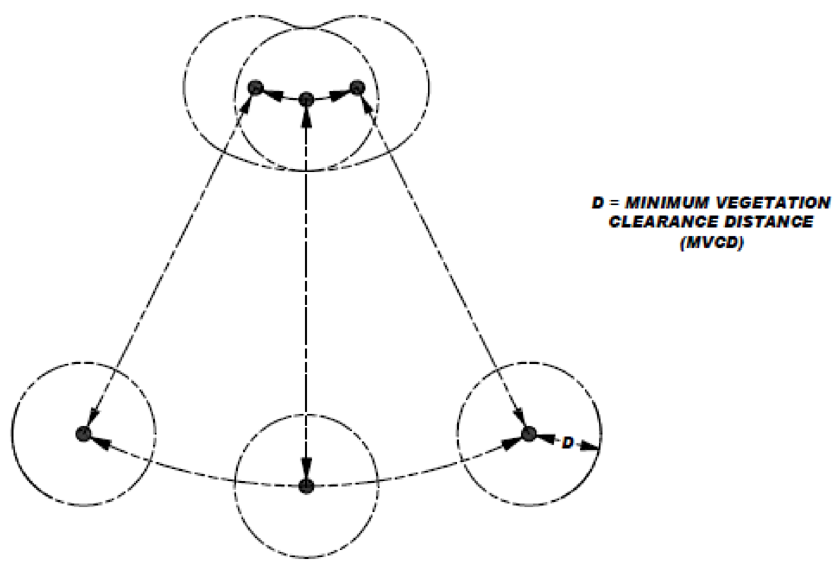

Figure 1

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 herbicides to control incompatible vegetation outside of the MVCD, 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 its 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.

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 used 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-003-1 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 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 was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

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

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

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

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

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-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.

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.