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EXHIBIT A

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UTILITY VEGETATION MANAGEMENT AND BULK ELECTRIC RELIABILITY REPORT FROM THE FEDERAL ENERGY REGULATORY COMMISSION

SEPTEMBER 7, 2004

Executive Summary

Electric transmission owners and operators conduct vegetation management to prevent physical contact between transmission lines and nearby vegetation that could cause a transmission line to fail. On August 14, 2003, an electric power blackout affected large portions of the Northeast and Midwest United States and Ontario, Canada. President George W. Bush and Prime Minister Jean Chrétien established a joint U.S.-Canada Power System Outage Task Force (Task Force) to investigate the causes of the blackout and how to reduce the possibility of future outages. On April 5, 2004, the Task Force issued a Final Blackout Report[1] stating that one of the four primary causes of the blackout was inadequate vegetation management (tree pruning and removal).

In response to the Final Blackout Report, the Federal Energy Regulatory Commission (Commission) directed all designated transmission owners to file reports with the Commission by June 17, 2004, explaining their vegetation management practices for designated transmission facilities and rights-of-way.[2] The Commission staff worked with the leadership of the National Association of Regulatory Utility Commissioners' (NARUC) ad-hoc Committee on Critical Infrastructure to analyze these reports to look for significant patterns and potential problems in the vegetation management practices of the electric industry. This report to Congress summarizes the Commission's findings and recommendations. In this report, the Commission also recommends that Congress enact legislation providing for mandatory, enforceable reliability rules.

Key Observations

The transmission owners were asked to report on the results of their most recent transmission line vegetation management inspections, necessary remedial actions identified, and whether such actions had been completed before the summer 2004 peak

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[1] U.S.-Canada Power System Outage Task Force, Final Report on the August 14th Blackout in the United States and Canada: Causes and Recommendations (April 2004) (Final Blackout Report).

[2] Order Requiring Reporting on Vegetation Management Practices Related to Designated Transmission Facilities, 107 FERC ¶ 61,053 (2004) (Vegetation Management Order). "Designated transmission facilities" are defined, for the purposes of the Vegetation Management Order only, as transmission lines with a rating of 230 kV or higher as well as tie-line interconnection facilities between control areas or balancing authority areas (regardless of kV rating) and "critical" lines as designated by the regional reliability council. *See* NERC, August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts at 9 n.3 (Feb. 10, 2004).

load season. Review of the vegetation management filings found that it appears transmission owners and operators have performed extensive vegetation management along the nation's high-voltage transmission network, which should produce better grid reliability during the summer. However, there is a wide range of vegetation management practices and procedures among the reporting transmission owners. There is very little uniformity in regard to right-of-way width,[3] vertical line clearance,[4] inspection frequency,[5] and vegetation management guidelines[6] used. The lack of uniformity may be understandable in part, as transmission owners must design their vegetation management practices based on factors such as the demands of the terrain, location, climate, vegetation species, and local laws and regulations.

The Commission recognizes that, while the data filed in response to the Vegetation Management Order reveals each transmission owner's practice, it does not directly address how effective the practice has been in limiting preventable transmission line outages. The Commission did not ask for such data in the April request, because similar data are now being reported to the Western Electricity Coordinating Council and to the North American Electric Reliability Council (NERC). Such a review is beyond the scope of this report.

Transmission owners report that they are not able to acquire all necessary permits to maintain their rights-of-way from various federal and state agencies. However, this problem could be alleviated, at least in part, if the acquisition of these permits is made a higher priority on the part of transmission owners. For instance, transmission owners could allow additional lead time to acquire many needed permits. The agencies responsible for issuing permits, however, should ensure that they have clear rules and procedures for issuing permits in a timely manner.

With respect to any jurisdiction issues that may arise involving vegetation management, it is important that state and federal regulators continue to coordinate so that jurisdictional considerations do not impede effective vegetation management.

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[3] A right-of-way is a segment of land used for the route of a transmission line. A right-of-way should be devoid of vegetation that can interfere with a transmission line. The right-of-way width is the distance between the outer bounds of a right-of-way.

[4] The vertical distance between a tree or vegetation and an electric transmission wire.

[5] The time between complete inspections of a utility's transmission system, *e.g.*, semiannual, annual, etc.

[6] The guidelines that utilities report they adhere to in regards to the management of vegetation along transmission lines.

The Commission believes that better coordination among federal agencies and between the federal and state governments to develop clear, consistent policies and procedures for timely and effective vegetation management by transmission owners could help to alleviate many real and perceived obstacles to proper vegetation management.

The transmission owners reported that vegetation management approvals on federally managed rights-of-way are particularly problematic in the Western United States. The Council on Environmental Quality (CEQ) coordinates federal environmental efforts and helps resolve inter-agency differences over environmental issues. The Commission believes federal agencies and the CEQ should work together on vegetation management on federal rights-of-way. In addition, the CEQ could facilitate coordination with Native American tribes for vegetation management on Native American tribal lands. We understand that vegetation management practices affect the environment and look forward to working with other agencies to coordinate efforts to assure that neither the environmental quality of federal lands nor regional electric reliability are put at risk.

Summary of Recommendations

1) The United States Congress should enact legislation to make reliability standards mandatory and enforceable under federal oversight.

2) Effective transmission vegetation management requires clear, unambiguous, enforceable standards that adequately describe actions necessary by each responsible party.

3) With respect to any jurisdiction issues that may arise involving vegetation management, it is important that state and federal regulators continue to coordinate so that jurisdictional considerations do not impede effective vegetation management.

4) Federal and state regulators should allow reasonable recovery for the costs of vegetation management expenses.

5) While permitting and environmental requirements properly protect public lands, the procedures implementing those protections may be inconsistent and time-consuming and have the potential to significantly hinder transmission vegetation management. The Commission should work with the CEQ and land management agencies to better coordinate these requirements.

6) Federal, state and local land managers should develop "rush" procedures and emergency exemptions to allow utilities to correct "danger" trees[7] that threaten transmission lines, from both on and off documented rights-of-way.

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[7] A danger tree is a tree that is dead or dying and has the potential to fall into a

7) Five-year vegetation management cycles should be shortened, and the Commission and states should look at the cost-effectiveness of more aggressive vegetation management practices.

8) Transmission owners should fully exercise their easement rights for vegetation management and better anticipate and manage the permitting process for scheduled vegetation management.

9) Variances in vegetation management practices may be resolved in the NERC vegetation management standard development process; if they are not, the Commission may seek to convene the industry, states and other stakeholders to address the remaining issues.

10) State regulators and the utility industry should work through NARUC, the National Conference of State Legislators, and other organizations to help state and local officials better understand and address transmission vegetation management.

Introduction

On August 14, 2003, an electric power blackout occurred over large portions of the Northeast and Midwest United States and Ontario, Canada. The blackout lasted up to two days in some areas of the United States and longer in some areas of Canada. It affected an area with over 50 million people and 61,800 megawatts of electric load. In the wake of the blackout, a joint U.S.-Canada Task Force (Task Force) undertook a study of the causes of that blackout and possible solutions to avoid future such blackouts. The Task Force's Final Report was issued on April 5, 2004.

The Task Force identified FirstEnergy Corporation's (FirstEnergy) failure to adequately prune trees and manage vegetation in its transmission rights-of-way as one of the four primary causes of the August 14, 2003 blackout.[8] The blackout investigation explained that, during the hour before the cascading blackout occurred, three FirstEnergy 345 kV transmission lines failed as a result of contact between the lines and overgrown vegetation that encroached into the required clearance zone for the lines.[9] It stated that "because the trees were so tall . . . each of these [three] lines faulted under system conditions well within specified operating parameters."[10]

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right-of-way close to a line.

[8] Final Blackout Report at 20.

[9] *Id.* at 57-67.

[10] *Id.* at 58.

The Final Blackout Report also compared the August 2003 blackout with seven previous major outages and concluded that conductor contact with trees was a common factor among the outages.[11] The Task Force emphasized that vegetation management is critical, and that many outages can be prevented by managing vegetation before it becomes a problem.[12] It also noted that investigation reports from previous major outages recommended paying special attention to the condition of vegetation on rights-of-way and the need for preventative maintenance in this area.

In March 2004, the Commission made available to the public a 128-page vegetation management report, prepared to support the blackout investigation.[13] The report details problems with vegetation management relating to the August 2003 blackout, and the impact of vegetation management on electric reliability. The report concludes that the August 2003 blackout likely would not have occurred had the rights-of-way been maintained for three 345 kV transmission lines that tripped due to tree-line contacts.[14] It also concludes that utilities responsible for the right-of-way maintenance had in place vegetation management programs that were in line with current industry norms. Further, it concludes that current industry "standards" are inadequate and must be improved. The CNUC Final Vegetation Report recommends specific practices that would reduce the likelihood of tree and power line contacts and provides recommendations for the oversight and enforcement of utility vegetation management activities.

On April 19, 2004, the Commission issued the Vegetation Management Order requiring all entities that own, control or operate designated electric transmission facilities in the lower 48 states to provide information on their vegetation management practices. This order was issued pursuant to section 311 of the Federal Power Act, 16 U.S.C. § 825j (2000) which authorizes the Commission to conduct investigations in order to secure information necessary or appropriate as a basis for recommending legislation.

The Commission ordered that designated transmission owners describe in detail the practices and standards that the transmission owner uses for control of vegetation near designated transmission facilities, and indicate the source of any standard utilized (*e.g.* state law or regulation, historical practice). In addition, transmission owners were asked

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[11] *Id.* at 107.

[12] *Id.* at 59.

[13] CN Utility Consulting, Utility Vegetation Management Final Report, (March 2004) (CNUC Final Vegetation Report). The CNUC Final Vegetation Report is available on the Internet at www.ferc.gov/cust-protect/moi/blackout.asp.

[14] *Id.* at 26-27.

to describe the clearance assumptions or definition used for the appropriate distance between vegetation and the facilities, how often the transmission provider inspects that facility for vegetation management purposes, whether identified remediation has been completed as of June 14, 2004, and any factors that the respondent believes prevents, or unduly delays, the performance of adequate vegetation management.[15]

This report analyzes the information gathered pursuant to the Vegetation Management Order, provides relevant additional information regarding the current status of vegetation management practices, and offers a recommendation for Congressional consideration.

Review and Analysis Method

The Commission received 161 responses from transmission owners.[16] On June 21-22, 2004, Commission staff, along with three state commissioners, Connie Hughes of New Jersey, Don Mason of Ohio, and Judith Ripley of Indiana, representing the leadership of the NARUC ad-hoc Committee on Critical Infrastructure, performed an initial review of the vegetation management responses.[17] This initial two-day review was intended to identify any immediate issues that could potentially impact electric grid reliability requiring rapid follow up by state or federal regulators. In addition, it looked for progress made since the blackout of the previous year, fact patterns suggesting additional inquiry is required, and a general overview of current vegetation management practices. The initial review was followed up by a more intensive Commission staff data analysis. This analysis included the creation of a database that tracked:

- all respondents' right-of-way width maintained in feet by voltage,
- vertical line clearance in feet by voltage,
- ground and aerial inspection frequency,
- vegetation management cycle,[18] and
- vegetation management guidelines utilized, if any.

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[15] Vegetation Management Order at P 12.

[16] Some respondents provided responses on behalf of multiple operating companies or multiple transmission owners.

[17] Edison Electric Institute (EEI) prepared templates for its members to use in filing the requested data. Many EEI members used these templates. The templates made it easier for Commission staff to review the filings.

[18] The period of time required for a utility to perform maintenance including the pruning of all vegetation and the removal of all vegetation of concern on its entire transmission system.

Commission staff reviewed the data in the five categories above and looked for patterns in vegetation management practices.[19]

Findings

The majority of respondents have completed necessary vegetation management remediation measures identified during the most recent inspection of their transmission lines. While this does not guarantee that there will not be adverse impact to grid reliability caused by vegetation interfering with transmission lines, it is a positive indication of reduced risk to reliability. However, 29 percent of respondents identified some line vegetation management remediation that was not completed by the June 17 filing date and may not be performed this summer.[20] A list of these respondents is provided in Attachment A. The results suggest that a significant amount of the remediation occurred between April 19, 2004 and June 14, 2004.

Utility vegetation management practices vary significantly. While some variation is expected because vegetation management practices are affected by climate, terrain, vegetation species, local laws, and regulations, other variations are unexplained. Below is a discussion of reported data on right-of-way width, vertical clearances, inspection frequency, vegetation management cycles, and vegetation management guidelines followed. Some of these variations may be resolved in the NERC vegetation management standard development process;[21] if they are not, the Commission may seek to convene the industry, states and other stakeholders to address the remaining issues.

1. Right-of-way Width

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[19] In their filings, certain respondents asked for and were granted protection regarding specific transmission line information under the Commission's Critical Energy Infrastructure Information (CEII) policy. CEII is information concerning proposed or existing critical infrastructure (physical or virtual) that relates to the production, generation, transmission or distribution of energy. While this report does not disclose any specific CEII data, the Commission's conclusions reflect its review of such data.

[20] In some instances, the transmission owner/operator reported that remediation before the summer was not needed and would be completed as part of the regular vegetation management cycles later in the year. In other instances, the respondent states that there is no immediate threat to the line. Some stated that the work would be completed shortly after June 17 or as soon as possible. In at least one case, the required work was pending reaching agreement with a landowner.

[21] NERC recently initiated a vegetation management standard development process. *See* ftp://www.nerc.com/pub/sys/all_updl/docs/bot/Agenda-Items-0604/Item12e.pdf.

Right-of-way widths vary significantly among the reporting transmission owners. Generally, right-of-way width increases as line voltage increases. Higher voltage lines require wider rights-of-way because greater separation is needed between conductors. Wider right-of-way widths are also necessary to accommodate multiple lines and in some cases more than one tower. Since right-of-way width depends on many factors, and since some respondents provided ranges that depend on such factors as the number of circuits on a right-of-way, no pattern was identified from the data on the range of right-of-way widths. Table 1 shows the range of responses by voltage class.

Table 1. Right-of-Way Width

Right-of-Way Width							
500 kV		345 kV		230 kV		Less than 230 kV	
Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies
Less than 125	4	Less than 75	6	Less than 75	40	Less than 50	51
126-175	21	76-125	36	76-125	36	51-125	41
176 >	13	126 >	30	126 >	30	126 >	7

In general, if a utility has a wider right-of-way, well documented right-of-way easement rights, and exercises those rights fully, it will be more successful in avoiding vegetation-line contact than a utility that maintains narrower rights-of-way. A narrow right-of-way increases the risk of contact with vegetation that is outside of the right-of-way and adjacent to the transmission line. Expert commentary included in the CNUC Final Vegetation Report stated, "[m]ost tree/power line contacts occur when trees fall onto lines from outside the rights-of-ways or corridors. Many utilities are slow to act to address this issue due to the perception of increased costs and the pressure from landowners etc. to leave trees standing."[22]

2. Inspection Frequency

Vegetation management inspections are performed to inspect the status of vegetation and the rights-of-way surrounding electric transmission facilities. During these inspections, vegetation of concern is noted and scheduled for remediation. Typically, a utility will utilize a combination of aerial and ground inspections. Ground inspections are performed by walking or driving the length of transmission lines to inspect the condition of vegetation. While slow, ground inspections may be more effective because they enable an inspector to more thoroughly view vegetation conditions and the relationship between vegetation and the wire. Aerial inspections are performed using aircraft (a helicopter or a small plane flying at low altitude) to visually inspect the

[22] CNUC Final Vegetation Report at 115.

condition of vegetation. Given the greater distance from the vegetation and the speed of aerial inspection, it is considered to be less reliable and thorough than ground inspection.

Annual, semi-annual, or more frequent aerial patrols are part of the transmission inspection practice of 105 utilities, twenty-five of which conduct aerial inspections more frequently than twice a year. Table 2 summarizes the responses.

Table 2. Aerial Inspection Frequency

Aerial Inspection	
Frequency	# of Companies
More than twice a year	25
Semi-annual	34
Annual	46
Biennial	6
Every 3 years	1
> than 3 Years	3
As Needed	8
Did Not Report	38

Most transmission owners use aerial patrols to identify areas that need remediation or areas that will need remediation soon. Aerial inspections are followed by additional ground inspection or remediation.

Over 100 respondents indicate that they conduct annual or more frequent ground inspections of their entire system. Ground patrols are more effective in identifying vegetation-related problems.[23] Table 3 summarizes the responses.

[23] CNUC Final Vegetation Report at 49.

Table 3. Ground Inspection Frequency

Ground Inspection	
Frequency	# of Companies
More than twice a year	7
Semi-annual	22
Annual	76
Biennial	6
Every 3 years	6
> than 3 Years	25
As Needed	12
Did Not Report	7

As with right-of-way width, patrol frequency and method varies significantly among reporting utilities. This could be due to the variation in the number of transmission circuit miles owned or operated by the utility, terrain, and vegetation characteristics.

3. Vertical Clearance

Vertical clearance is the distance between a wire and the vegetation directly below it.[24] The minimum vertical clearance requirement increases by line voltage (although some transmission owners reported the same vertical clearance for all voltage classes). The maintenance of sufficient vertical distance between the conductor and vegetation is essential because direct physical contact is not necessary for a line outage to occur. An electric arc can occur between a part of a tree and a nearby high-voltage conductor without sufficient clearance.[25] These electric arcs can cause fires and line outages. Vegetation management practices should maintain a minimum vertical clearance between a line and a tree. The pruning should create clearances with a healthy safety margin beyond the minimum required clearance that will last until the next scheduled pruning or treatment. Table 4 shows vertical clearances used by reporting utilities.

[24] Vegetation can interfere with power lines from below, sides, and above and appropriate clearance must be maintained all around the wire. This section discusses vertical line clearance as an example of the variation among utilities in maintaining line clearances.

[25] In effect, electricity on a transmission wire can "jump" a very short distance from the wire to tree limbs without direct contact, creating a short circuit that can lead to a line outage.

Table 4. Vertical Clearances Reported

Vertical Clearance Table							
500 kV		345 kV		230 kV		Less than 230 kV	
Clearance (ft)	# of Companies	Clearance (ft)	# of Companies	Clearance (ft)	# of Companies	Clearance (ft)	# of Companies
0-15	11	0-15	17	0-10	23	0-10	16
16-20	11	16-20	17	11-15	17	11-15	20
21-25	9	21-25	12	16-20	24	16-20	14
26>	8	26 >	14	21-25	16	21-25	3
				26 >	13	26 >	5

There is no apparent rationale for the wide variance in vertical clearance requirements.[26] The current industry effort through NERC to develop a vegetation management standard should resolve this issue.

4. Vegetation Management Cycle

A vegetation management cycle is loosely defined as the time it takes to complete the pruning and removal of trees or other vegetation on a utility's entire transmission system. In most cases, a utility prunes or treats a portion of its total circuit-miles of right-of-way in each year; once the circuit is completed, the company starts the cycle over. The Vegetation Management Order did not formally request this information, but the CNUC Final Vegetation Report found that a five-year cycle is the industry norm. Furthermore, the report found that the five-year cycle is insufficient to maintain reliability.

Of the 70 respondents that volunteered their vegetation management cycles, many indicate that they prune and remove vegetation along their lines within a five-year or longer interval.[27] Table 5 summarizes the responses.

[26] There could have been varying interpretations of the reporting requirement (*e.g.*, clearance achieved at the time of pruning vs. minimum clearance maintained). However, the EEI templates used by a large number of respondents instructed that "minimum clearance maintained between conductor and vegetation" be reported.

[27] A five-year cycle is consistent with the industry practice; however, common or average industry practices need improvement. Final Blackout Report at 59.

Table 5. Pruning Cycle

Pruning Cycle	
Frequency	# of Companies
0-2 years	11
3-4 years	35
5 or More years	24

In the future, the Commission and the industry should work to identify the correlation between vegetation management practices and actual vegetation-caused transmission line outages.

When managing vegetation, 93 companies employ herbicides to limit vegetation growth; others use mechanical techniques to cut vegetation on rights-of-way; and some use a combination of both.[28]

5. Current Vegetation Management Guidelines

Establishing clear, unambiguous standards pertaining to maintenance of safe clearances of transmission lines from obstructions in rights-of-way was one of the recommendations of the Final Blackout Report.[29] The vast majority of transmission owners report that they follow the National Electrical Safety Code (NESC) rules or American National Standards Institute (ANSI) guidelines, or both when managing vegetation around transmission lines. The NESC deals with electric safety rules, including transmission wire clearance standards, while the applicable ANSI code deals with the practice of pruning and removal of vegetation. However, these rules and guidelines are not specific with regard to clearances between transmission lines and vegetation and are subject to interpretation. Nor do these rules provide a performance target for keeping vegetation from conflicting with transmission lines. Furthermore, these standards are not enforceable upon transmission owners, but have been adopted by NESC and ANSI as guidelines for appropriate practice.

- 104 utilities indicate that they adhere to NESC standards for transmission system maintenance.
- 92 of these specifically adhere to NESC Rule 218, which only provides that

[28] Mechanical and chemical techniques are not mutually exclusive in general. Rather, mechanically clearing, *e.g.* with a bushhog, might take place followed by treatment with herbicide to retard regrowth.

[29] Final Blackout Report at 154.

trees that may interfere with conductors should be trimmed or removed. NESC Rule 218 does not prescribe clearances.
- 12 reported that they specifically follow NESC Rule 232, 233 or 234 which prescribes clearances of wires from ground, structures, and other installations.
- 34 respondents follow ANSI A300, which deals with proper tree pruning techniques to maintain the health of the tree, and does not contain any clearance requirements.
- ANSI Z133, used by 22 transmission owners, provides guidelines for utilities related to worker and public safety during tree pruning and removal operations.
- A large number of respondents adhere to NESC standards in conjunction with ANSI standards such as A300.
- 96 transmission owners report that they use internally-developed, state, or other guidelines.

Respondents did not explain why they follow a particular standard. As stated earlier, NERC is in the process of developing a vegetation management standard that may resolve the current lack of a clear, unambiguous standard.

Good Practices

The CNUC Final Vegetation Report identified a number of good utility vegetation management practices. Among these good practices for existing rights-of-way are:

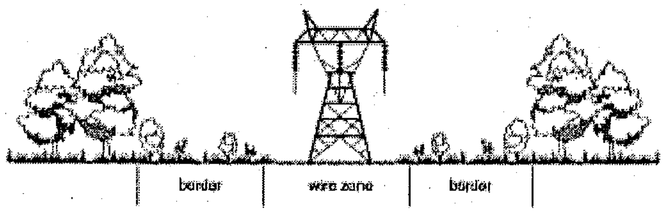
- Application of wire zone – border zone concepts (described below)
- Proper consideration of line sag and sway
- Frequent field inspection of vegetation conditions
- Comprehensive public education programs

In reviewing the filings, Commission identified a number of utilities that report practices consistent with the best practices identified in the CNUC Final Vegetation Report. Some examples follow.

One good practice relates to customer education. For example, some utilities have public outreach programs that educate the public about tree types and line clearances so that citizens will have the knowledge to report vegetation that is dangerous to transmission wires.

Several transmission owners employ a wire zone – border zone approach which is both environmentally friendly and effective in ensuring reliability. This method involves creating a low-growing vegetation environment directly under transmission lines, which physically prevents dangerous vegetation from encroaching into energized transmission facilities. The CNUC Final Vegetation Report stated that the wire zone-border zone has "been proven to be effective in reducing and/or eliminating outages related to vegetation on transmission ROW [rights of way]."[30] The wire zone-border zone concept is depicted in the graphic below.

Bramble and Byrnes Wire Zone – Border Zone
(From Yahner, Bramble and Byrnes, 2000)



Several companies have taken measures to improve vegetation management-related reliability. Certain utilities, for example, conduct frequent ground and aerial patrols, as well as an inspection of all of its power lines after every major storm.

Reported Obstacles to Effective Vegetation Management

In trying to understand the state of the industry's vegetation management programs, the Vegetation Management Order sought information on factors that the utilities believe prevent or unduly delay their performance of adequate vegetation management. Sixty-six utilities report that their efforts to properly maintain their transmission lines are impeded by a variety of federal and state regulations that legally or practically prevent them from performing effective vegetation management. While such ordinances can be problematic and hinder the vegetation management process, proper planning and foresight on the part of the utilities, including allowances for additional lead time, would likely reduce the threat to vegetation management caused by some ordinances.

[30] CNUC Final Vegetation Report at 21.

List of Reported Obstacles	
Reported Obstacles	**Responses**
U.S. Forest Service	22
U.S. Fish and Wildlife Service	12
National Park Service	6
Departments of Transportation	6
Other Federal/State/Local Governments	35
Private Landowners	20
Other	10

No transmission owners complained of the financial costs of vegetation management.

In many instances, a situation may arise in which a transmission owner is not able to plan for vegetation management. For example, trees can become hazardous to a line suddenly, as when a tree is dead or dying and has the potential to fall into a right-of-way and impact a line. These are a risk to reliability as long as the situation is not corrected, and so must be dealt with on a priority basis. Many transmission owners reported that the permitting processes can impede action necessary to properly manage situations such as this.

The conflicting goals and requirements for environmental protection and electric reliability create practical problems for vegetation management. Transmission owners cite federal regulations and their enforcement programs most frequently as impeding their ability to properly manage the vegetation within transmission line rights-of-way.[31] Twenty-two transmission owners cited U.S. Forest Service (Forest Service) restrictions on transmission owners across the country. They state that the Forest Service requires impact studies on wildlife and habitat impacts, requires environmental impact assessments, and limits the use of access roads to transmission rights-of-way and has inconsistent permitting procedures across the National Forests. In addition, twelve utilities claim that the U.S. Fish and Wildlife Service restricts the times at which trees can be pruned and limits herbicide use in order to maintain endangered species habitats. If

[31] Some of the land management agencies have already begun streamlining their permitting processes. For example, the Forest Service began overhauling its permitting and environmental review process over a year ago. These changes should reduce the impact of permitting on vegetation management.

herbicide use is limited, many manually or mechanically removed trees can re-sprout and quickly grow back into power lines. Utilities also report that the various state Departments of Transportation had restricted tree pruning and removal in the name of "beautification" efforts. Otter Tail Power reports that the U.S. Department of Transportation, the U.S. Fish and Wildlife Service, and the Department of Natural Resources have repeatedly planted trees in its rights-of-way.

Several companies stated that state government organizations had taken action that they believed hindered their reliability programs as well. For instance, PacifiCorp reports that the Utah Department of Transportation had planted trees directly under several of its 345 kV transmission lines and would not allow them to be pruned. The New York State Department of Environmental Conservation requires transmission owners to file "Temporary Revocable Permits" that take up to two years to process for transmission owners to get access to trees that need to be managed.

Respondents also claim that a variety of local regulations and property owners prevent effective vegetation management. One of the most frequent claims is local and private entities limit the use of herbicides and the removal of trees. Some local park restrictions hinder trucks from accessing power lines. Native American tribes are sovereign and can restrict transmission owners in numerous ways when transmission rights-of-way pass through tribal land. For many utilities, attempting to manage numerous local and private restrictions can be extremely burdensome and can result in failure to conduct effective vegetation management. For example, the outage that occurred on Cinergy's 345 kV Columbus – Bedford line on August 14, 2003 was due to a property owner's refusal to allow Cinergy to complete the required work.[32] Cinergy had documented rights at the location but work was halted due to a court-granted temporary injunction obtained by the property owner.

Need For Legislation

Ineffective vegetation management was a major cause of the August 14, 2003 blackout and a contributing factor to other large-scale blackouts. The U.S.-Canada Task Force found that clear, unambiguous, and enforceable standards are needed to reduce the potential for reoccurrence of vegetation related transmission line outages and recommended that NERC, in cooperation with the industry and the appropriate governmental agencies, develop such a standard.[33] The Commission's review of the responses submitted confirms a lack of common standards and significant variations among utilities in their vegetation management practices.

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[32] CNUC Final Vegetation Report at 36.

[33] Final Blackout Report at 154.

NERC recently initiated a vegetation management standard development process. The Commission supports NERC's initiative to develop a clear, unambiguous vegetation management standard. However, adherence to NERC standards will be voluntary unless Congress enacts legislation with a clear federal framework for mandating development and enforcement of this and other reliability rules.

Recommendations

The following recommendations are based on the information received in response to the Vegetation Management Order. The Commission has also drawn from the Blackout Report and the CNUC Final Vegetation Report. These recommendations were developed in collaborative discussions between the Commission staff and the state commissioners who participated in the initial review.

1) The United States Congress should enact legislation to establish an Electric Reliability Organization and make its standards mandatory and enforceable, under federal oversight. Under such legislation, if the Commission were to approve a NERC standard, then it would be mandatory and enforceable for all transmission owners and operators. Mandatory, enforceable standards will result in greater compliance and, therefore reduce the likelihood of individual transmission line outages due to tree contacts, electric arcing, and fires, and thus improve local and regional grid reliability.

2) Effective transmission vegetation management requires clear, unambiguous, enforceable standards that adequately describe the actions necessary by each responsible party. The NERC standard now being developed should serve this purpose. We recognize that the details of such standards must respect differing vegetative, climate, terrain, and other considerations, and thus may need to balance between results required and detailed prescriptions for how to manage vegetation, so it will be challenging to develop a clear, effective standard. But it must be done, and done as quickly as possible to assure that the nation's customers and economy do not remain at risk to this known reliability threat.

3) With respect to any jurisdiction issues that may arise involving vegetation management, it is important that state and federal regulators continue to coordinate so that jurisdictional considerations do not impede effective vegetation management.

4) As noted above, no reporting utility suggests that lack of financial resources or recovery of vegetation management expenses is an obstacle to the achievement of vegetation management goals. Nevertheless, both federal and state regulators should be sensitive to requests for rate adjustments in order to recover reasonable reliability and security related expenses such as those for vegetation management.[34]

[34] *See, e.g.*, Policy Statement on Matters Related to Bulk System Reliability, 107

5) The Commission should work with the CEQ and the federal land management agencies to streamline and better coordinate permitting and environmental requirements to facilitate better vegetation management without compromising environmental quality. While it is entirely appropriate that federal and state land managers protect the lands for which they have responsibility, the costs and consequences of vegetation-caused outages or blackouts are so high that agencies should reexamine these processes and requirements to see whether they need to be reformed. The Commission commits to work with the CEQ and other federal land management agencies on such an effort. Additionally, the CEQ could facilitate coordination with Native American Tribes for vegetation management on Native American tribal lands.

6) Outages are often caused by trees that become hazardous to a line, as when a tree is dead or dying and has the potential to fall into a right-of-way and impact a line. These are a risk to reliability as long as the situation is not corrected, and so must be dealt with on a priority basis. State, local and federal land managers should recognize the importance of this situation and should develop priority or rush procedures to allow the utility to take prompt corrective action to mitigate these "danger" trees.

7) Since numerous recent major blackouts have been caused by tree contacts with transmission lines, and the August 14, 2003 blackout was caused by trees that were managed on a five-year vegetation management cycle, the CNUC Final Vegetation Report concluded that a five-year cycle, while the industry norm, is not effective nor adequate for assuring transmission reliability across much of North America. For that reason, a shorter cycle should be used. While this and other enhanced vegetation management requirements suggested herein may increase utility costs, given the substantial and perhaps growing costs of reliability failures of the modern grid, the Commission and the states should encourage cost-benefit studies to examine the relative costs and benefits of current and more aggressive vegetation management practices.

8) Transmission owners should work to remove the obstacles to effective vegetation management along transmission rights-of-way. This should include, at minimum:

- Whenever possible, renegotiation of easement provisions where they do not grant adequate clearance and vegetation management rights.
- Full exercise of all existing easement provisions and rights to assure adequate tree-pruning and clearing.
- Where landowners or land managers have established lengthy permitting requirements or time-limited vegetation management operational windows, planning ahead to assure that the transmission owner or operator secures the

FERC ¶ 61,052 at P 27-28 (2004).

needed permissions in a timely and predictable fashion.

9) Variances in vegetation management practices may be resolved in the North American Electric Reliability Council (NERC) vegetation management standard development process; if they are not, the Commission may seek to convene the industry, states and other stakeholders to address the remaining.

10) State regulators and the utility industry should approach NARUC, National Conference of State Legislators, and similar organizations to develop model guidelines and educational materials that can be used to help state and local officials understand the importance of this issue and how to manage it more effectively, through measures such as tree-pruning and tree-planting ordinances. If state legislation or changed agency rules are needed, utilities and state utility regulators should take the lead within each state to initiate the communications and cooperative discussions required. The Commission would support this effort, if requested.

Attachment A

Companies that did not perform all identified vegetation management remediation by the June 14, 2004 reporting date

- American Transmission Co.
- Aquila, Inc.
- Austin Energy
- Basin Electric Power Cooperative
- Black Hills Power, Inc.
- Carolina Power and Light Co.
- Central Hudson Gas and Electric Corp.
- Central Louisiana Electric Company, Inc.
- City of Tallahassee Electric Utility
- Consolidated Edison Company of New York, Inc.
- Dairyland Power Cooperative
- Entergy Corp.
- Georgia Transmission Corp.
- Indiana-Kentucky Electric Corporation
- International Transmission Co.
- Lakeland Electric
- Louisville Gas & Electric Co.
- Lower Colorado River Authority Transmission Services Corp.
- Montana-Dakota Utilities Co.
- Municipal Electric Authority of Georgia
- Nebraska Public Power District
- New York Power Authority
- NorthWestern Energy
- Nstar Electric and Gas Corp.
- Ohio Valley Electric Corp.
- Oklahoma Gas & Electric Co.
- PacifiCorp
- PPL Electric Utility Corp.
- Public Utility District No.1 of Chelan County
- Puget Sound Energy, Inc.
- Rappahannock Electric Cooperative
- Santee Cooper Power
- Seattle City Light
- Sierra Pacific Power Co.
- South Carolina Gas & Electric Co.
- South Texas Electric Cooperative, Inc.
- Texas Municipal Power Agency
- Tucson Electric Power Co.
- TXU Electric Delivery
- Western Area Power Administration
- Xcel Energy

In some instances, the transmission owner/operator reported that remediation before the summer was not needed and would be completed as part of the regular vegetation management cycles later in the year. In other instances, the respondent states that there is no immediate threat to the line. Some stated that the work would be completed shortly after June 17 or as soon as possible. In at least one case, the required work was pending reaching agreement with a landowner. On August 26, 2004, Dairyland Power Cooperative filed an update with the Commission stating that all remediation has been completed.

Attachment B

Primary Contributors

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EXHIBIT B

EXHIBIT B

118 FERC ¶ 61,218
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

(Docket No. RM06-16-000; Order No. 693)

Mandatory Reliability Standards for the Bulk-Power System

(Issued March 16, 2007)

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. Those Reliability Standards meet the requirements of section 215 of the FPA and Part 39 of the Commission's regulations. However, although we believe it is in the public interest to make these Reliability Standards mandatory and enforceable, we also find that much work remains to be done. Specifically, we believe that many of these Reliability Standards require significant improvement to address, among other things, the recommendations of the Blackout Report. Therefore, pursuant to section 215(d)(5), we require the ERO to submit significant improvements to 56 of the 83 Reliability Standards that are being approved as mandatory and enforceable. The remaining 24 Reliability Standards will remain pending at the Commission until further information is provided.

The Final Rule adds a new part to the Commission's regulations, which states that this part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii) and requires that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies. The new regulations also require that each Reliability Standard that is approved by the Commission will be maintained on the ERO's Internet website for public inspection.

impact assessment procedure to provide a consistent and uniform methodology that can be applied by any Regional Entity. Ontario IESO does not support the Commission's proposal to limit case-by-case determinations to underlying transmission systems operating at less than 100 kV.

b. Commission Determination

75. The Commission agrees with commenters that, at least initially, expanding the scope of facilities subject to the Reliability Standards could create uncertainty and might divert resources as the ERO and Regional Entities implement the newly created enforcement and compliance regime. Further, we agree with commenters that unilaterally modifying the definition of the term bulk electric system is not an effective means to achieve our goal. For these reasons, the Commission is not adopting the proposed interpretation contained in the NOPR. Rather, for at least an initial period, the Commission will rely on the NERC definition of bulk electric system[47] and NERC's registration process to provide as much certainty as possible regarding the applicability to and the responsibility of specific entities to comply with the Reliability Standards in the start-up phase of a mandatory Reliability Standard regime.[48]

76. However, we disagree with NERC, APPA and NRECA that there is no intentional distinction between Bulk-Power System and bulk electric system. NRECA states that "[W]here Congress borrows terms of art in which are accumulated the legal tradition and meaning of centuries of practice, it presumably knows and adopts the cluster of ideas that were attached to each borrowed word in the body of learning from which it was taken."[49] In this instance, however, Congress did not borrow the term of art – bulk electric system – but instead chose to create a new term, Bulk-Power System, with a definition that is distinct from the term of art used by industry. In particular, the statutory term does not establish a voltage threshold limit of applicability or configuration as does the NERC definition of bulk electric system. Instead, section 215 of the FPA broadly defines the Bulk-Power System as "facilities and control systems necessary for operating an

[47] "As defined by the Regional Reliability Organization, 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."

[48] See Section II.C.2., Applicability to Small Entities, infra.

[49] Citing Morissette v. United States, 342 U.S. 246, 263 (1952).

interconnected electric energy transmission network (or any portion thereof) [and] electric energy from generating facilities needed to maintain transmission system reliability." Therefore, the Commission confirms its statements in the NOPR that the Bulk-Power System reaches farther than those facilities that are included in NERC's definition of the bulk electric system.[50]

77. Although we are accepting the NERC definition of bulk electric system and NERC's registration process for now, the Commission remains concerned about the need to address the potential for gaps in coverage of facilities. For example, some current regional definitions of bulk electric system exclude facilities below 230 kV and transmission lines that serve major load centers such as Washington, DC and New York City.[51] The Commission intends to address this matter in a future proceeding. As a first step in enabling the Commission to understand the reach of the Reliability Standards, we direct the ERO, within 90 days of this Final Rule, to provide the Commission with an informational filing that includes a complete set of regional definitions of bulk electric system and any regional documents that identify critical facilities to which the Reliability Standards apply (i.e., facilities below a 100 kV threshold that have been identified by the regions as critical to system reliability).

78. The Commission believes that the above approach satisfies concerns raised by NARUC and New York Commission that the proposal to interpret Bulk-Power System exceeds the Commission's jurisdiction. When the Commission addresses this matter in a future proceeding, it will consider NARUC's and New York Commission's comments regarding the "layer of 'area' transmission."

79. We disagree with commenters claiming that the ERO's definition of bulk electric system is broader than the statutory definition of Bulk-Power System. Connecticut Attorney General, Connecticut DPUC and others argue that the ERO's definition of bulk electric system exceeds the Commission's jurisdiction by including generation that is not needed to maintain transmission system reliability and, therefore, intrudes into state jurisdiction over generation resource adequacy. First, none of the Reliability Standards submitted by the ERO set requirements for resource adequacy. Moreover, commenters have not adequately supported their claim that the "threshold" in the NERC definition of bulk electric system that includes facilities "generally operated at 100 kV or higher" is

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[50] NOPR at P 66. For these same reasons, the Commission rejects the position of those commenters that suggest the statutory definition of Bulk-Power System is more limited than the NERC definition of bulk electric system.

[51] See id. at P 64-65 & n.53-54.

2.45-foot clearance from a live conductor for the 120 kV voltage class,[270] whereas the ANSI Z-133 standard specifies 12 feet, 4 inches as the approach distance for the 115 kV voltage class.[271]

732. Accordingly, the Commission directs the ERO to develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land. While this consensus is developed, the Commission directs the ERO to address any potential issues regarding mitigation measures needed to assure these minimum clearances on Forest Service lands are appropriate on a case-by-case basis. The Commission also directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.

733. In regard to California PUC's concern about its ability to impose stricter requirements on vegetation clearances, the Commission notes that section 215(i)(3) of the FPA states that nothing in section 215 shall be construed to preempt the authority of a state to take action to ensure the reliability of electric service within that state, as long as the action is not inconsistent with any Reliability Standard. Therefore, the State of California may set its own vegetation management requirements that are stricter than those set by the Commission as long as they do not conflict with those set by the Commission. Further, the Commission notes that once a Reliability Standard is established, California PUC can develop stricter rules to be applied within the state of California, and if it wants them to be enforceable under section 215 of the FPA, could submit those Reliability Standards to the ERO and the Commission for approval as a regional difference.

734. FirstEnergy suggests that rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way. The Commission believes this suggestion is

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[270] Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 516-2003, IEEE Guide for Maintenance Methods at 20.

[271] ANSI Z133, American National Standards Institute Standard for Tree Care Operations – Pruning, Trimming, Repairing, Maintaining and Removing Trees, and Cutting Brush – Safety Requirements.

EXHIBIT C

EXHIBIT C

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**
2. **Number:** FAC-003-1
3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).
4. **Applicability:**
   - **4.1.** Transmission Owner.
   - **4.2.** Regional Reliability Organization.
   - **4.3.** This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.
5. **Effective Dates:**
   - **5.1.** One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.
   - **5.2.** Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

RRO

NERC

1.2. Compliance Monitoring Period and Reset

One calendar Year

1.3. Data Retention

Five Years

1.4. Additional Compliance Information

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1:

2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

2.2. Level 2:

2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

2.3. Level 3:

2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06

EXHIBIT D

EXHIBIT D

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

June 4, 2008

Ms. Kimberly Bose
Secretary
Federal Energy Regulatory Commission
888 *First* Street, N.E.
Washington, D.C. 20426

Re: NERC Notice of Penalty regarding Baltimore Gas & Electric Company, FERC Docket No. NP08-_-000

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) hereby provides this Notice of Penalty regarding Baltimore Gas & Electric Company,[1] in accordance with the Federal Energy Regulatory Commission's (Commission or FERC) rules, regulations and orders, as well as NERC Rules of Procedure including Appendix 4C NERC Compliance Monitoring and Enforcement Program (CMEP).[2]

This Notice of Penalty is being filed with the Commission because, based on information from Reliability*First* Corporation, Baltimore Gas & Electric Company submitted a self-report of its violation of FAC-003-1 Requirement (R.) 2. Baltimore Gas & Electric Company has accepted the violation and the proposed penalty of $180,000 to be assessed to Baltimore Gas & Electric Company at issue in this Notice of Penalty. Accordingly, the violation identified as NERC Violation Tracking Identification Number RFC200700002 is a Confirmed Violation, as that term is defined in the NERC Rules of Procedure and the CMEP.

Statement of Findings Underlying the Violations

This Notice of Penalty incorporates by reference the findings and justifications set forth in the Notice of Confirmed Violation and Proposed Penalty or Sanction (NOC) issued on April 28, 2008, by Reliability*First* Corporation. The details of the findings and basis for the penalty are set forth in Table 1 of the NOC, as well as the determinations of the NERC Board of Trustees Compliance Committee (NERC BOTCC) in its decision. In accordance with Section 39.7 of the

[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards* (Order No. 672), III FERC Stats. & Regs. ¶ 31,204 (2006); *Notice of New Docket Prefix "NP" for Notices of Penalty Filed by the North American Electric Reliability Corporation*, Docket No. RM05-30-000 (February 7, 2008). *See also* 18 C.F.R. Part 39 (2008). *Mandatory Reliability Standards for the Bulk-Power System*, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *reh'g denied*, 120 FERC ¶ 61,053 (2007) (Order No. 693-A).
[2] *See* 18 C.F.R § 39.7(c)(2).

Commission's regulations, 18 C.F.R. § 39.7 (2007), NERC provides the following summary table identifying each Reliability Standard violated by Baltimore Gas & Electric Company.

NOP ID	Regional Entity	Registered Entity	NOC ID	NERC Violation ID	Rel. Std.	Req. (R)	VRF	Total Penalty ($)
NOP-38	RFC	Baltimore Gas and Electric Company	NOC-55	RFC200700002	FAC-003-1	2	High	180,000

FAC-003 R. 2 provides that a Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

Baltimore Gas & Electric Company submitted, to Reliability*First* Corporation, a self-report of its failure to maintain, pursuant to NERC Reliability Standard FAC-003-1 R.2, the appropriate clearance between a tree and a conductor in accordance with its Vegetation Management Plan, which resulted in a 230 kV transmission line outage on August 15, 2007. The line was returned to service on August 16, 2007.

NERC stated its interpretation of the vegetation management standard during FERC's consideration of proposed FAC-003-1: A vegetation-related transmission line outage as a result of vegetation that has grown into the pre-defined clearance zone is a violation of the standard.[3] The Commission adopted that interpretation when it approved NERC's proposed reliability standards. It stated, "FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions."[4] Because violations of the Requirements 1 and 2 of FAC-003-1 could directly lead to or contribute to widespread outages or cascading failures, NERC assigned "High" Violation Risk Factors to those requirements. NERC stated, "Clearly, the failure to have a vegetation management program with appropriate clearances, and an annual work plan could directly (and has) contribute to widespread outages."[5]

[3] *Comments of the North American Electric Reliability Council and the North American Electric Reliability Corporation on Staff Preliminary Assessment*, Docket No. RM06-16-000, filed June 26, 2006, p. 31.
[4] *Mandatory Reliability Standards for the Bulk-Power System*, FERC Stats. & Regs. ¶ 31,242 at P 729 (2007) (Order No. 693).
[5] *Request of the North American Electric Reliability Corporation for Approval of Supplemental Violation Risk Factors for Version 1 Reliability Standards*, Docket No. RR07-12-000 (May 4, 2007), at Exhibit A.

The Commission confirmed that interpretation and understanding when it approved NERC's proposed violation risk factors for FAC-003-1, stating:

> With regard to FAC-003-1, Requirement R1 requires a transmission owner to develop a transmission vegetation management program, and Requirement R2 requires a transmission owner to implement the program. NERC's assignment of a "high" Violation Risk Factor to Requirements R1 and R2 is appropriate because inadequate vegetation management presents a serious risk of sustained transmission outage and could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures. Both planning and implementation are critical to vegetation management. A vegetation-related transmission outage would result in a violation of Requirement R1, R2 or both.[6]

FAC-003-1 has a "High" VRF. In its NOC, the Reliability*First* Corporation did not assess a Violation Severity Level (VSL) because the standard as approved utilizes Levels of Non-Compliance. Reliability*First* Corporation has assigned Level 3 (equivalent to a "High" VSL) as the Level of Non-Compliance for this violation. Based on the NERC Sanction Guidelines Base Penalty Table, the possible penalty range for a "High" VRF is $4,000 to $1,000,000.

Status of Mitigation Plan[7]

Baltimore Gas & Electric Company's Mitigation Plan was accepted by Reliability*First* Corporation on February 15, 2008 and was approved by NERC on February 26, 2008. The Mitigation Plan for the violation listed in Table 1 is designated as MIT-07-0427 and was submitted as non-public information to FERC on February 26, 2008 in accordance with FERC orders. Baltimore Gas & Electric Company certified on March 31, 2008 to Reliability*First* Corporation that its Mitigation Plan was completed, and Reliability*First* Corporation verified in a document dated June 2, 2008 that the Mitigation Plan was completed.

Statement Describing the Proposed Penalty, Sanction or Enforcement Action Imposed[8]

FERC Order Excerpts

In Order No. 693, the Commission provided guidance to NERC and the industry on the determination of penalties during the first six month period of mandatory and enforceable Reliability Standards:

> 222. . . . In light of commenters' concerns, including the fact that there are new aspects to the Reliability Standards and the proposed compliance program that will apply to all users, owners and operators of the Bulk-Power System, *the Commission directs the ERO and Regional Entities to focus their resources on the*

[6] *North American Electric Reliability Corporation*, Order on Violation Risk Factors, 119 FERC ¶ 61,321 at P 10 (June 26, 2007).
[7] *See* 18 C.F.R § 39.7(d)(7).
[8] *See* 18 C.F.R § 39.7(d)(4).

most serious violations during an initial period through December 31, 2007. This thoughtful use of enforcement discretion should apply to all users, owners and operators of the Bulk-Power System, and not just those new to the program as originally proposed in the NOPR. This approach will allow the ERO, Regional Entities and other entities time to ensure that the compliance monitoring and enforcement processes work as intended and that all entities have time to implement new processes.

223. *By directing the ERO and Regional Entities to focus their resources on the most serious violations through the end of 2007, the ERO and Regional Entities will have the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant.* Further, even if the ERO or a Regional Entity declines to assess a monetary penalty during the initial period, they are authorized to require remedial actions where a Reliability Standard has been violated. Furthermore, where the ERO uses its discretion and does not assess a penalty for a Reliability Standard violation, we encourage the ERO to establish a process to inform the user, owner or operator of the Bulk-Power System of the violation and the potential penalty that could have been assessed to such entity and how that penalty was calculated. We leave to the ERO's discretion the parameters of the notification process and the amount of resources to dedicate to this effort. Moreover, the Commission retains its power under section 215(e)(3) of the FPA to bring an enforcement action against a user, owner or operator of the Bulk-Power System.

224. *The Commission believes that the goal should be to ensure that, at the outset, the ERO and Regional Entities can assess a monetary penalty in a situation where, for example, an entity's non-compliance puts Bulk-Power System reliability at risk.* Requiring the ERO and Regional Entities to focus on the most serious violations will allow the industry time to adapt to the new regime while also protecting Bulk-Power System reliability by allowing the ERO or a Regional Entity *to take an enforcement action against an entity whose violation causes a significant disturbance.* Our approach strikes a reasonable balance in ensuring that the ERO and Regional Entities will be able to enforce mandatory Reliability Standards in a timely manner, while still allowing users, owners and operators of the Bulk-Power System time to acquaint themselves with the new requirements and enforcement program. In addition, our approach ensures that all users, owners and operators of the Bulk-Power System take seriously mandatory, enforceable reliability standards at the earliest opportunity and before the 2007 summer peak season.[9]

[9] Order No. 693 at PP 222-224 (emphasis added).

Basis for Determination

Taking into consideration the Commission's direction in Order No. 693 and the NERC Sanction Guidelines, the NERC BOTCC reviewed the NOC and supporting documentation on April 24, 2008 and May 5, 2008.

The NERC BOTCC affirmed Reliability*First* Corporation's determination to exercise enforcement discretion to impose a $180,000 penalty against Baltimore Gas & Electric Company, based upon the NERC BOTCC's review of the applicable requirements of the Commission-approved Reliability Standards and the underlying facts and circumstances of the violations at issue.

In assessing this financial penalty, NERC and Reliability*First* Corporation considered the following: (1) There is no question that Baltimore Gas & Electric Company had a vegetation management plan and was implementing its plan; (2) Baltimore Gas & Electric Company was aware of the vegetation from prior patrols but allowed the vegetation to remain "because of resistance, for aesthetic reasons, by an adjacent property owner to the complete removal of trees from the site." The vegetation was scheduled to be removed on the next routine maintenance schedule in early 2008; (3) Baltimore Gas & Electric Company self-reported the vegetation and transmission line outage constituting the violation; (4) Baltimore Gas & Electric Company worked cooperatively with Reliability*First* Corporation; (5) Baltimore Gas & Electric Company acted immediately to mitigate and correct the violation; (6) The actions taken by Baltimore Gas & Electric Company ensure that reliability is maintained; and (7) Baltimore Gas & Electric Company accepted or did not contest the Reliability*First* Corporation findings of the violation or the proposed penalty.

Therefore, NERC believes that the proposed $180,000 penalty is appropriate and consistent with NERC's goal to ensure reliability of the bulk power system.

Pursuant to Order No. 693, the penalty will be effective upon expiration of the thirty (30) day period following the filing of this Notice of Penalty with FERC, or, if FERC decides to review the penalty, upon final determination by FERC.

The Record of the Proceeding[10]

The record of the proceeding includes the following documents and material in the Attachments below:

a) Baltimore Gas & Electric Company's Self-Report;

b) Notice of Alleged Violation and Proposed Penalty or Sanction. Baltimore Gas & Electric Company's response thereto;

[10] *See* 18 C.F.R § 39.7(d)(5).

c) Notice of Confirmed Violation and Penalty or Sanction. Baltimore Gas & Electric Company's response thereto;

d) Mitigation Plan designated as MIT-07-0427;

e) Baltimore Gas & Electric Company's certification of completion of the Mitigation Plans;

f) Reliability*First* Corporation's statement of verification that the Mitigation Plans have been successfully completed; and

g) NERC BOTCC Decision.

A Form of Notice Suitable for Publication[11]

A copy of a notice suitable for publication is included in Attachment h.

Notices and Communications

Notices and communications with respect to this filing may be addressed to the following:

Rick Sergel
President and Chief Executive Officer
David N. Cook*
Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Rebecca J. Michael*
Assistant General Counsel
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
rebecca.michael@nerc.net

*Persons to be included on the Commission's service list are indicated with an asterisk.

[11] *See* 18 C.F.R § 39.7(d)(6).

Conclusion

NERC respectfully requests that the Commission accept this Notice of Penalty as compliant with its rules, regulations and orders.

Respectfully submitted,

<u>/s/ Rebecca J. Michael</u>
Rebecca J. Michael
Assistant General Counsel
North American Electric Reliability Corporation
1120 G Street, N.W.
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(202) 393-3998
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Rick Sergel
President and Chief Executive Officer
David N. Cook
Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

cc: Baltimore Gas & Electric Company
Reliability*First* Corporation

Attachment(s)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Attachment a

Baltimore Gas & Electric Company's

Self-Report

RELIABILITY FIRST

COMPLIANCE MONITORING AND ENFORCEMENT PROGRAM
VIOLATION SELF-REPORTING FORM

This Violation Self-Reporting Form can be used for submittals via e-mail or fax for violations of the Reliability Standards identified by a self- assessment.

1. **Reliability Standard (XXX-###-#** or XXX-###-RFC-##) FAC-003-1

2. **Violation(s):** Check the appropriate box(s) to identify violation(s) of any of the applicable requirement(s) referenced in the standard.

   For violations of requirements with Levels of Non-Compliance or Violation Severity Levels (VSL) specified in the standard:

   ☐ Entity is Level 1 Non-Compliance or has Lower VSL for the following: requirement(s): ______ for function(s): ______

   ☐ Entity is Level 2 Non-Compliance or has Moderate VSL for the following: requirement(s): ______ for function(s): ______

   ☒ Entity is Level 3 Non-Compliance or has High VSL for the following: requirement(s): R 2 for function(s): TO

   ☐ Entity is Level 4 Non-Compliance or has Severe VSL for the following: requirement(s): ______ for function(s): ______

   For violations of requirements with no Levels of Non-Compliance or Violation Severity Levels specified in the standard:

   ☐ Entity is in violation of requirement(s) not referenced in the Levels of Non-Compliance or Violation Severity Levels section of the standard:

   requirement(s): ______ for function(s): ______

3. **Description of the violation:** Failure to maintain appropriate clearance between the tree and conductor at maximum emergency sag for a 230 kV interconnected transmission line in accordance with the BGE Annual Plan.

4. **Additional information:** The trees in the location where the incident occurred have been removed or trimmed. An inspection for all lines over 200 kV is under way to ascertain if additional tree-related threat potential exists.

5. **Mitigation Plan attached:** ☐ Yes ☒ No

6. **Officer Verification:** I understand that this information is being provided as required by the Reliability*First* Compliance Monitoring and Enforcement Program. Any review of this violation will require all information certified on this form be supported by appropriate documentation.

Officer's Name: Stephen J. Woerner [signature]

Officer's Title: Senior Vice President - Electric Business Operations and Planning

Officer's e-mail address: Stephen.J.Woerner@bge.com Phone: 410-597-6465

Registered Company Name: Baltimore Gas and Electric Company CDMS User ID: BGE

Primary Compliance Contact (PCC)/Alternate: Daniel Taormina

Email: dan.taormina@bge.com Phone: 410-597-7593 Date: 8/17/07

E-mail Submittals to: **compliance@rfirst.org or Fax#: 330- 456-5408 – Attention Compliance Dept.**
For any questions regarding compliance submittals, please e-mail: compliance@rfirst.org.

Reliability*First* Corporation
Transmission Owner
Vegetation Outage Report

Individual Vegetation Related Transmission Line Outage

For EACH outage experienced, complete the following table.

Outage # 1

Name of Transmission Owner (TO):	Baltimore Gas & Electric Company
Name of Transmission Line Involved in Outage: *(No circuit number please)*	Graceton to Raphael Rd (#2313)
Voltage of Transmission Line: *(Please mark one)*	☒ 230 kV class ☐ 345 kV class ☐ 500 kV class ☐ 765 kV class ☐ Reliability*First* Designated Critical Lines <200 kV
Time and date of outage:	August 15, 2007 @ 18:37
Duration of outage:	16 hrs. 16 min. (returned to service 8/16/07 @10:53)
Line-loading (% of normal rating) of the involved line at the time of line trip: **NOTE:** This information should be provided whenever vegetation grew up from within or outside of the ROW and contacted the line, or if the line sagged into the vegetation.	85.9% of normal rating 480 MVA Load 559 MVA Normal Rating; 674 MVA Emer Rating 95 Degree Temperature Set Rating
Description of cause of outage:	Pine tree on right of way between towers #86 and #87 caused arc and fault with conductor.
Caused by Category 1, Category 2, or Category 3 vegetation: **NOTE:** Please check whether or not a Category 1 outage occurred as a result of a tree from inside or outside the right-of-way.	☒ **Category 1 — Grow-ins:** Outages caused by vegetation growing into lines from vegetation inside and/or outside of the right-of-way. ☒ Inside the right-of-way ☐ Outside the right-of-way ☐ **Category 2 — Fall-ins:** Outages caused by vegetation falling into lines from inside the right-of-way. ☐ **Category 3 — Fall-ins:** Outages caused by vegetation falling into lines from outside the right-of-way.
Counter measures or corrective steps taken by TO including timeframe to prevent future outages:	-Offending tree removed and nearby trees trimmed between Towers #86 and #87 on August 16, 2007. -System wide inspection to identify and correct any other similar situations. - Detailed investigation is ongoing
Additional comments:	

RELIABILITY FIRST

<u>**Vegetation Outage Questionnaire – [FAC-003]**</u>

Transmission Owner: **Baltimore Gas and Electric Company**

Date of Reported Outage: **August 15, 2007**

These questions should be considered by the Transmission Owner when performing the root cause analyses. The Reliability*First* Staff will use these as a guide to assure various issues have been addressed.

1. Was the inspection of your transmission system on schedule in accordance with your transmission Vegetation Management Program? <u>Yes.</u>

2. What is the transmission line patrol cycle at the location of the vegetation outage? <u>Annual walking and biannual aerial patrols.</u>

3. When was this line last patrolled? <u>January 2007.</u>

4. How long has this identified vegetation been there? <u>The vegetation that was involved in the interruption was part of a larger body of vegetation that has occupied the site for approximately 30 years by our best estimates. Most of the tall-growing vegetation on the site had been removed in a phased-in manner within the last 20 years. The vegetation that was on-site on August 15, 2007 was the final remnant left from the original stand of trees and was allowed to remain because of resistance, for aesthetic reasons, by an adjacent property owner to the complete removal of the trees from the site. The remnant tall-growing vegetation was to have been removed in early 2008 on the next routine maintenance cycle.</u>

5. If it is determined that this vegetation was there at the time of the last patrol cycle, was it overlooked, missed, or was it recorded as being a potential problem area? <u>It was recorded as an area to continue to monitor.</u>

6. If it is determined that the vegetation was there at the time of the last patrol cycle, how was it overlooked as being a potential problem? <u>The heights of these specific trees were not measured with instrumentation but visually estimated, without a correct adjustment made for the maximum engineered sag of the conductor into the tree-wire clearance dynamic. The new NERC requirements were not yet mandatory and enforceable and had not been incorporated into the BGE Transmission Vegetation Management Program (TVMP) at the time of the last inspection of the area in question.</u>

RELIABILITY FIRST

7. What was the height of the vegetation that made contact with the transmission line via an electrical arc? 29 feet.

8. How is any activity, construction, strip mining, etc., performed adjacent to your transmission lines, monitored and controlled so it does not interfere with your system reliability? These types of activities are noted during the right of way inspections and from new subdivision property plans or other usage requests that are submitted to BGE or to local government planning processes by developers and other parties.

9. How are the entities performing activities, located within your area of responsibility, informed and kept informed of what specific activities are unacceptable in your transmission line right of way? Allowed activities are licensed and compliance with the terms of the licenses is monitored during the right of way inspections. Any activities that are not allowed are noted and the property owner is advised - verbally at first, and by mail as required, with legal action the final step in the process if compliance or elimination of the activity cannot be secured by the other means. This process is worked on a prioritized basis with situations involving safety and reliability addressed first.

10. If the outage was the result of activity in question 8 above, are there other locations that could have similar activity taking place? The transmission line outage was not related to activities such as those listed in Question 8.

11. What steps are being taken to assure that this activity does not pose a risk in other locations? The actions outlined in the response to question 9 are consistently applied to all BGE transmission line rights of way.

12. Will the steps, referenced in question 11, be an on-going activity? Yes.

13. Are risks from the identified activity mentioned in your Vegetation Management Program? If not, will they be added? BGE did not experience a transmission line outage as a result of activities listed in question 8.

14. Is there a "no activity zone", within your transmission lines right of way, indicating where activities are not permitted? No.

Officer's Name: Brian C. Daschbach, Sr. B C Daschbach, Sr 10-26-07
Officer's Title: Senior Vice President – Integrated Field Services
Officer's Email Address: brian.c.daschbach@bge.com
Officer's Phone Number: 410-470-5910

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Attachment b

Notice of Alleged Violation and Proposed Penalty of Sanction

and

Baltimore Gas & Electric Company's Response

Raymond J. Palmieri
Vice President and Director of Compliance

RELIABILITY*FIRST*

BALTIMORE GAS AND ELECTRIC COMPANY	) **DOCKET NUMBER**	**RFC200700002**
NERC Registry ID # NCR00689	)	
ALLEGED VIOLATION OF RELIABILITY STANDARD FAC-003-1 Requirement 2	)	

Notice of Alleged Violation and Proposed Penalty or Sanction

Date: March 18, 2008

In accordance with the NERC Rules of Procedure including Appendix 4C thereto and in conformity with the Reliability*First* Compliance Monitoring and Enforcement Program (CMEP), Reliability*First* Corporation (Reliability*First*) hereby notifies the Baltimore Gas and Electric Company of an Alleged Violation of a NERC Reliability Standard and the Proposed Penalty or Sanction. This Notice of Alleged Violation and Proposed Penalty or Sanction (Notice) takes the place of, supersedes and replaces in its entirety the previous Notice of Alleged Violation and Proposed Penalty or Sanction issued on February 27, 2008 with regard to this Docket Number.

In support hereof, Reliability*First* states as follows:

I. <u>Alleged Violation:</u>

On August 15, 2007, the Baltimore Gas and Electric Company was registered on the NERC Compliance Registry as a Distribution Provider (DP), Load Serving Entity (LSE), Purchasing – Selling Entity (PSE) and Transmission Owner (TO). As discussed herein, Reliability*First* has determined to charge the Baltimore Gas and Electric Company (BGE) with a violation based upon information available to it that BGE did not comply or was not in compliance with the NERC Reliability Standard listed below.

NERC Violation ID # RFC200700002

Reliability Standard: FAC-003-1

Requirement Allegedly Violated: Requirement 2

Date/Time of Alleged Violation:

The Reliability*First* Compliance Staff has reason to believe that the Alleged Violation occurred on August 15, 2007.

Alleged facts that give the Compliance Staff reason to believe that the Alleged Violation existed include the following:

On August 20, 2007, BGE submitted to Reliability*First* via email a Compliance Monitoring and Enforcement Program Violation Self-Reporting Form in which BGE identified Non-Compliance to Requirement 2 of Reliability Standard FAC-003-1.

Specifically, in the Self-Reporting Form, BGE stated that the violation involved a

> "[f]ailure to maintain appropriate clearance between the tree and conductor at maximum emergency sag for a 230 kV interconnected line in accordance with the BGE Annual Plan."

On August 20, 2007, BGE submitted to Reliability*First* via email a "Vegetation Outage Report" containing information regarding an outage on the 230 kV Graceton to Raphael Rd (#2313) transmission line which occurred on August 15, 2007 at 18:37, with the line being returned to service on August 16, 2007 at 10:53. The "Vegetation Outage Report", submitted by BGE, further states the cause of the outage as a "Pine tree on right of way between towers #86 and #87 caused arc and fault with conductor."

On October 26, 2007, BGE submitted to Reliability*First* via email a completed "Vegetation Outage Questionnaire – [FAC-003]" containing information related to the August 15, 2007 outage.

Specifically, in the Questionnaire, BGE stated that although the location of the outage was subject to annual walking and biannual aerial patrols, and the line in question was last patrolled in January of 2007,

> "[t]he vegetation that was involved in the interruption was part of a larger body of vegetation that has occupied the site for approximately 30 years by our best estimates. Most of the tall-growing vegetation on the site had been removed in a phased-in manner within the last 20 years. The vegetation that was on-site on August 15, 2007 was the final remnant left from the original stand of trees and was allowed to remain because of resistance, for aesthetic reasons, by an adjacent property owner to the

> complete removal of the trees from the site. The remnant tall-growing vegetation was to have been removed in early 2008 on the next routine maintenance cycle."

Specifically, in the Questionnaire, BGE also stated that, although the location of the outage "was recorded as an area to continue to monitor" prior to the August 15, 2007 outage, that,

> "[t]he heights of these specific trees were not measured with instrumentation but visually estimated, without a correct adjustment made for the maximum engineered sag of the conductor into the tree-wire clearance dynamic."

Requirement 2 of FAC-003-1, states in part,

> "The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. ….The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. …. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications."

BGE failed to effectively implement a vegetation management plan that took into account the anticipated vegetation growth of a known stand of trees located inside the right-of-way thus resulting in a transmission line outage.

II. <u>Proposed Penalty and/or Sanction:</u>

Pursuant to the Federal Energy Regulatory Commission's (FERC or Commission) regulations and orders, NERC Rules of Procedure and the NERC Sanction Guidelines, Reliability*First* proposes to assess a penalty for the violation of the Reliability Standard referenced in Section I in the amount of $180,000 USD.

If BGE does not dispute the Notice of Alleged Violation and Proposed Penalty or Sanction or a decision has been entered finding a violation and all appeals have been concluded, NERC shall file a Notice of Penalty with FERC. NERC will include with the Notice of Penalty any statement provided by BGE as set forth in CMEP Section 8.0. NERC may direct Reliability*First* to revise a penalty determination that clearly conflicts with the goal of consistent national reliability enforcement, in which case any participant may reopen the proceedings on any issue, irrespective of whether the issue was previously litigated, settled or unopposed.

The penalty or sanctions will be effective upon expiration of the thirty (30) day period following filing with FERC of the Notice of Penalty or, if FERC decides to review the penalty or sanction, upon final determination by FERC.

III. Registered Entity Response:

As required by Section 5.1 of the NERC CMEP, within 30 days of the date of service of this notification, BGE must file with Reliability*First* in writing its decision to elect one of the following options:

1. BGE agrees to or does not contest the Alleged Violation and Proposed Penalty and/or Sanction, and agrees to submit and implement a Mitigation Plan to correct the violation and its underlying causes;

2. BGE agrees to or does not contest the Alleged Violation and agrees to submit and implement a Mitigation Plan to eliminate the violation and its underlying causes, but contests the Proposed Penalty and/or Sanction; or

3. BGE contests the Alleged Violation and the Proposed Penalty and/or Sanction for the Alleged Violation.

With respect to election options 1-3, BGE may submit a response in accordance with CMEP Section 5.2. BGE's statement must be on company letterhead and must include the name, title, and signature of an officer of BGE. The mitigation plan and time line for completion must be accepted by both the Reliability*First* and NERC.

If BGE does not contest or does not respond to the notice of violation within thirty (30) days, it shall be deemed to have accepted Reliability*First's* preliminary determination of violation and proposed penalty or sanction (as applicable), in which case Reliability*First* shall issue to BGE and NERC a report of Confirmed Violation.

If BGE contests the Alleged Violation, the proposed penalty or the proposed sanction, BGE shall submit to Reliability*First* a response explaining its position, signed by an officer or equivalent, together with any supporting information and documents within thirty (30) days. BGE shall provide a primary contact name who will be the responsible party to respond to questions regarding the above Alleged Violations. Reliability*First* shall schedule a conference with BGE within ten (10) business days after receipt of the response. If Reliability*First* and BGE are unable to resolve all issues within forty (40) days after BGE's response, BGE may request a hearing. If no hearing request is made, the violation will become a Confirmed Violation when filed by NERC with FERC. The Reliability*First* Hearing Procedure governs the hearing process. BGE may appeal the hearing body's decision in accordance with the CMEP and the NERC Rules of Procedure.

IV. Settlement:

Reliability*First's* Settlement Procedures, a copy of which is available on the Compliance page of the Reliability*First* web site, and CMEP Section 5.4 govern the settlement process and provide that settlement negotiations may occur at any time until Notice of Penalty, Sanction or Other Enforcement Action is filed with FERC.

V. Mitigation Plan Procedures and Requirements:

Procedurally, CMEP Section 6.0 sets forth the provisions regarding the submittal of a mitigation plan. A Registered Entity found to be in violation of a Reliability Standard shall file with the applicable Regional Entity (i) a proposed Mitigation Plan to correct the violation, or (ii) a description of how the violation has been mitigated, and any requests for extensions of Mitigation Plans or a report of completed mitigation. CMEP Section 6.2 requires that a Mitigation Plan include the following information:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section 2.0 of the CMEP.

(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.

(3) The cause of the Alleged or Confirmed Violation(s).

(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).

(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed Violation(s).

(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.

(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.

(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of

submission. Additional violations could be determined for not completing work associated with accepted milestones.

(9) Any other information deemed necessary or appropriate.

The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity.

CMEP Section 6.4 provides that a Mitigation Plan may be submitted at any time but shall have been submitted by the Registered Entity within thirty (30) days after being served the Notice of Alleged Violation and Penalty or Sanction, if the Registered Entity does not contest the violation and penalty or sanction. If the Registered Entity disputes the Notice of Alleged Violation or penalty or sanction, the Registered Entity shall submit its Mitigation Plan within ten (10) business days following issuance of the written decision of the hearing body, unless the Registered Entity elects to appeal the hearing body's determination to NERC.

BGE has chosen to submit a Mitigation Plan with respect to this Alleged Violation. This submission shall not be deemed an admission of the violation or the appropriateness of a penalty or sanction nor does the submission of a Mitigation Plan result in waiver of the BGE's right to contest the Alleged Violation and/or the proposed penalty or sanction.

Any violations assessed during the period of time the accepted Mitigation Plan is being implemented will be recorded by Reliability*First* with associated sanctions or penalties. Reliability*First* will report any findings of violations recorded during this time period to NERC with the notation that BGE is working under an accepted Mitigation Plan with an extended completion date with penalties and sanctions held in abeyance until completion of the Mitigation Plan. Upon completion of the accepted Mitigation Plan in accordance with CMEP Section 6.6, the Compliance Enforcement Authority will notify BGE that any findings of violations of the applicable Reliability Standards during the period that the accepted Mitigation Plan was being implemented have been waived and no penalties or sanctions will apply. Reliability*First* will also notify NERC of any such waivers of violations of Reliability Standards.

A request for an extension of any milestone or the completion date of the accepted Mitigation Plan by BGE must be received by Reliability*First* at least five (5) business days before the original milestone or completion date. The terms of the mitigation plan and time line for completion may be modified only upon express written approval Reliability*First* and NERC.

VI. Mitigation Plan and Implementation Status:

On January 22, 2008, BGE submitted to Reliability*First* its Mitigation Plan to address the Alleged Violation set forth in this notice. BGE's Mitigation Plan was accepted by Reliability*First* on February 15, 2008. On February 15, 2008, the Mitigation Plan was sent to NERC for their approval. In accordance with the NERC Rules of Procedure, Appendix 4C, no additional penalties will be assessed by Reliability*First* for violations subject to the Mitigation

Plan that occur during the time period in which the accepted Mitigation Plan is being implemented unless the mitigation is not successfully completed in accordance with the timetable set forth in the Mitigation Plan or an agreed upon extension thereof granted by Reliability*First*.

BGE is required to provide regular status updates regarding the implementation of the accepted Mitigation Plan. These status updates must be provided when significant milestones are achieved, if BGE begins to fall behind the accepted mitigation plan timeline or when any significant change in status warrants. In any case, status updates will be provided at least every ninety (90) days until the mitigation plan is completed.

BGE must certify successful completion at the conclusion of the mitigation plan. Also, Reliability*First* may ask for additional evidence to support successful completion of the accepted mitigation plan and Reliability*First* may elect to perform an on-site review as verification.

VII. Hearing Process:

The Reliability*First* Hearing Procedure governs the hearing process. BGE may appeal the hearing body's decision in accordance with the Reliability*First* CMEP and the NERC Rules of Procedure.

If BGE elects to contest the Alleged Violation and/or the proposed penalty or sanction, BGE shall state in a written hearing request that it is electing to have a hearing conducted pursuant to either (i) the short-form procedure in the Reliability*First* Hearing Procedure Section 1.3.2 or (ii) the full hearing procedure, in the Reliability*First* Hearing Procedure.

BGE may appeal the hearing body's decision in accordance with the CMEP and the NERC Rules of Procedure.

VIII. Reservations:

The allegations of the violation of a Reliability Standards, and the proposed Penalties or Sanctions set forth herein constitute the position of Reliability*First's* Compliance Staff at the time of this Notice's issuance. The alleged factual and documentary bases for the Compliance Staff's positions set forth herein are subject to change and modification based upon any additional information and document obtained and/or reviewed by the Compliance Staff during the course of further investigation or the hearing process provided for by Reliability*First's* Hearing Procedures. Further, the positions of the Compliance Staff set forth herein are not to be construed as ultimate findings of fact or law by the Reliability*First's* Hearing Body. The Hearing Body's decision on the allegations set forth herein will be rendered in the form of a Final Order in accordance with Section 1.7.8 of Reliability*First's* Hearing Procedures.

Please direct any questions in response to this Notice of Alleged Violation and Proposed Penalty or Sanction to the undersigned. In your reply correspondence to this notice, please provide the

CONFIDENTIAL

name and contact information of BGE's representative who is authorized to respond to questions regarding the above-listed Alleged Violation and who is responsible for providing the required Mitigation Plan. Also, please reference the corresponding docket number in all correspondence related to this matter.

Respectfully submitted,

Raymond J. Palmieri

Raymond J. Palmieri
Reliability*First* Corporation
Vice President and Director of Compliance

cc: NERC Manager of Enforcement and Mitigation

Reliability*First*

Tim Gallagher – President
Robert Wargo – Senior Consultant, Compliance

BGE

Ken DeFontes – President and CEO
Stephen J. Woerner – Senior Vice President, Electric Business Operations & Planning
Daniel Taormina – Transmission Compliance Consultant

Stephen J. Woerner, P.E.
Senior Vice President
Electric Business Operations & Planning

7309 Windsor Mill Road
Baltimore, Maryland 21244
410.597.6465 EOB-RBC
410.470.5280 G&E Bldg.
443.213.3264 Fax
stephen.j.woerner@bge.com

BGE

April 9, 2008

Mr. Raymond J. Palmieri
Vice President and Director of Compliance
ReliabilityFirst Corporation
320 Springside Drive, Suite 300
Akron, Ohio 44333

Re: Docket No. RFC 200700002
Baltimore Gas and Electric Company Notice of Election

Dear Mr. Palmieri:

Pursuant to ReliabilityFirst Corporation's (ReliabilityFirst) March 18, 2008 Notice of Alleged Violation and Proposed Penalty or Sanction (Notice), Baltimore Gas and Electric Company (BGE) hereby: (1) submits its election of Option 1 contained therein; (2) confirms that it has complied with the requirement therein to submit and implement a Mitigation Plan, with a certified completion date of March 31, 2008; and (3) designates the undersigned as the BGE representative who is authorized to respond to questions regarding the Notice.

The vegetation related outage was timely detected, reported, and remedied without injury and without service interruption. BGE has long maintained an effective vegetation management program, and regrets even a single incident whereby any overgrowth leads to an outage. In order to more fully safeguard against any such reoccurrence, BGE's exhaustive vegetation management plan is now enhanced by the Mitigation Plan that ReliabilityFirst accepted and submitted for approval to the North American Reliability Council on February 15, 2008. The Mitigation Plan details the remedial measures undertaken, such as removing/trimming the trees in the immediate location where the outage occurred, conducting an inspection of all transmission lines over 200 kV for any potential vegetation issues, contracting with a third party consulting company to independently review and confirm BGE's inspection, enhancing its training program, and designing clear mitigation measures for protection of transmission facilities for locations where BGE has been restricted from attaining the specified clearances.

BGE commends ReliabilityFirst for promptly processing this matter.

Sincerely,

Stephen J. Woerner

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Attachment c

Notice of Confirmed Violation and Penalty or Sanction

RELIABILITY FIRST

BALTIMORE GAS AND ELECTRIC COMPANY	) **DOCKET NUMBER**
	) **RFC200700002**
NERC Registry ID # NCR00689	)
CONFIRMED VIOLATION OF RELIABILITY STANDARD FAC-003-1 Requirement 2	)

Notice of Confirmed Violation and Proposed Penalty or Sanction

Date: April 28, 2008

Reliability*First* hereby provides this Notice of Confirmed Violation and Proposed Penalty or Sanction regarding the Baltimore Gas and Electric Company,[1] in accordance with the Federal Energy Regulatory Commission's (Commission or FERC) rules, regulations and orders, the NERC Rules of Procedure including Appendix 4C (NERC Compliance Monitoring and Enforcement Program) and the Reliability*First* Compliance Monitoring and Enforcement Program (CMEP).[2]

I. Reliability*First* Process

Reliability*First* is issuing this Notice of Confirmed Violation and Proposed Penalty or Sanction, because Baltimore Gas and Electric Company (BGE) does not dispute the alleged violation and the proposed penalty or sanction set forth in the previously issued Notice of Alleged Violation and Proposed Penalty or Sanction. Accordingly, the violation identified by the above Docket Number and listed below is a Confirmed Violation, as that term is defined in the NERC Rules of Procedure and the CMEP.

II. NERC Process

Reliability*First* is providing a copy of this Notice of Confirmed Violation and Proposed Penalty or Sanction to NERC for its review and consideration. Upon acceptance by the NERC Board of Trustees Compliance Committee, in its current form or as modified, NERC will provide the Notice of Proposed Penalty or Sanction to FERC, with a copy to BGE and Reliability*First*. Following NERC action, FERC may act to accept, reject or modify the findings and/or penalties or sanctions set forth herein.

[1] *See* 18 C.F.R § 39.7(d)(1).
[2] *See* 18 C.F.R § 39.7(c)(2).

III. Violation of Reliability Standards

In accordance with Section 39.7 of the Commission's regulations, 18 C.F.R. § 39.7 (2007), Reliability*First* provides the following information regarding the Reliability Standard violated by BGE including a statement by Reliability*First* setting forth the findings of fact with respect to the act or practice resulting in the violation of the Reliability Standard.

On August 15, 2007, the Baltimore Gas and Electric Company was registered on the NERC Compliance Registry as a Distribution Provider (DP), Load Serving Entity (LSE), Purchasing – Selling Entity (PSE) and Transmission Owner (TO).

NERC Violation ID # RFC200700002

Reliability Standard:	FAC-003-1
Requirement Violated:	Requirement 2
Date/Time of Violation:	August 15, 2007
Date of Discovery by Region:	August 20, 2007
Discovery Method:	Self-Report
Date or Period of Violation:	One Occurrence on August 15, 2007

Facts and Evidence of the Act or Practice Resulting in the Violation[3]

On August 20, 2007, BGE submitted to Reliability*First* via email a Compliance Monitoring and Enforcement Program Violation Self-Reporting Form in which BGE identified Non-Compliance to Requirement 2 of Reliability Standard FAC-003-1.

Specifically, in the Self-Reporting Form, BGE stated that the violation involved a

> "[f]ailure to maintain appropriate clearance between the tree and conductor at maximum emergency sag for a 230 kV interconnected line in accordance with the BGE Annual Plan."

On August 20, 2007, BGE submitted to Reliability*First* via email a "Vegetation Outage Report" containing information regarding an outage on the 230 kV Graceton to Raphael Rd (#2313) transmission line which occurred on August 15, 2007 at 18:37, with the line being returned to service on August 16, 2007 at 10:53. The "Vegetation Outage Report", submitted by BGE, further states the cause of the outage as a "Pine tree on right of way between towers #86 and #87 caused arc and fault with conductor."

[3] *See* 18 C.F.R § 39.7(d)(3).

On October 26, 2007, BGE submitted to Reliability*First* via email a completed "Vegetation Outage Questionnaire – [FAC-003]" containing information related to the August 15, 2007 outage.

Specifically, in the Questionnaire, BGE stated that although the location of the outage was subject to annual walking and biannual aerial patrols, and the line in question was last patrolled in January of 2007,

> "[t]he vegetation that was involved in the interruption was part of a larger body of vegetation that has occupied the site for approximately 30 years by our best estimates. Most of the tall-growing vegetation on the site had been removed in a phased-in manner within the last 20 years. The vegetation that was on-site on August 15, 2007 was the final remnant left from the original stand of trees and was allowed to remain because of resistance, for aesthetic reasons, by an adjacent property owner to the complete removal of the trees from the site. The remnant tall-growing vegetation was to have been removed in early 2008 on the next routine maintenance cycle."

Specifically, in the Questionnaire, BGE also stated that, although the location of the outage "was recorded as an area to continue to monitor" prior to the August 15, 2007 outage, that,

> "[t]he heights of these specific trees were not measured with instrumentation but visually estimated, without a correct adjustment made for the maximum engineered sag of the conductor into the tree-wire clearance dynamic."

Requirement 2 of FAC-003-1, states in part,

> "The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. ....The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. .... The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications."

BGE failed to effectively implement a vegetation management plan that took into account the anticipated vegetation growth of a known stand of trees located inside the right-of-way thus resulting in a transmission line outage.

Proposed Penalty or Sanction

Pursuant to the Federal Energy Regulatory Commission's (FERC or Commission) regulations and orders, NERC Rules of Procedure and the NERC Sanction Guidelines, Reliability*First* proposes to assess a penalty for the violation of the Reliability Standard referenced above in the amount of $180,000 USD.

The proposed amount is based on the violation being a singular occurrence limited to the event that took place on August 15, 2007 and reflects the risk factor associated with the violated requirement as well as the severity of the violation when considering the overall seriousness of the violation. Additional factors considered in determination of the proposed penalty amount included the self-reported discovery nature of the violation, the cooperation of BGE during the violation assessment phase, the timely voluntary nature of their corrective actions, and the strength and quality of the compliance program in place at BGE.

IV. Statement Describing Any Proposed Penalty or Sanction Imposed[4]

Reliability*First* has determined to assess BGE with a total proposed penalty of $180,000 USD based upon information available to Reliability*First* that BGE did not comply or was not in compliance with the NERC Reliability Standard identified above.

This proposed penalty or sanction is subject to review and possible revision by NERC and FERC. NERC will include its determination of the proposed penalty or sanction in a Notice of Proposed Penalty or Sanction to be filed with FERC.

The proposed penalty or sanction will be effective upon expiration of the thirty (30) day period following the acceptance and the filing of the Notice of Proposed Penalty or Sanction with FERC by NERC, or, if FERC decides to review the proposed penalty, or sanction, upon final determination by FERC.

V. Other Matters of Relevance[5]

BGE's mitigation plan was accepted by Reliability*First* on February 15, 2008 and by NERC on February 26, 2008. The Mitigation Plan for the violation listed above is designated as NERC ID No. MIT-07-0427 and was submitted as non-public information to FERC on February 26, 2008 in accordance with applicable statutes, regulations and FERC orders. On March 31, 2008, BGE certified, as of that date, successful completion of all elements identified in the accepted and approved Mitigation Plan.

In accordance with the NERC Rules of Procedure, Appendix 4C, no additional proposed penalties or sanctions will be assessed by Reliability*First* unless the mitigation was not successfully completed in accordance with the timetable set forth in the mitigation plan. Reliability*First* may ask for additional evidence to support successful completion of the accepted mitigation plan and Reliability*First* may elect to perform an on-site review as verification.

VI. Statement Provided by the Registered Entity (CMEP Sections 5.6 and 8.0)

In accordance with CMEP Section 8.0, the Regional Entity must report to NERC and the affected Registered Entity all Confirmed Violations of Reliability Standards including all penalties, sanctions, Mitigation Plans and schedules, and settlements, within ten (10) business days of each determination. Reliability*First* hereby provides notice that BGE may provide a statement to NERC, with a copy to Reliability*First*, within five (5) business days after the date of this Notice of Confirmed Violation and Proposed Penalty or Sanction, to accompany the report when posted by NERC. BGE's statement may be the same statement provided by BGE in

[4] *See* 18 C.F.R § 39.7(d)(4).
[5] *See* 18 C.F.R § 39.7(d)(7).

response to the Notice of Alleged Violation and Proposed Penalty or Sanction. BGE's statement must be on Baltimore Gas and Electric Company letterhead and must include the name, title, and signature of an officer, employee, attorney or other authorized representative of BGE.

NERC will publicly post each report of a Confirmed Violation, together with any statement submitted by BGE, no sooner than five (5) business days after the report is provided by Reliability*First* to NERC and BGE. NERC will include, with the Notice of Penalty filed with FERC, the statement provided by BGE, in accordance with CMEP Section 5.6.

VII. The Record of the Proceeding[6]

The record of the proceeding includes this Notice of Confirmed Violation and Proposed Penalty or Sanction and any BGE statement or response thereto, as well as the following documents and material (to the extent applicable), attached hereto:

a) Compliance Monitoring and Enforcement Program Violation Self-Reporting Form, (Dated August 17, 2007 – Submitted to Reliability*First* on August 20, 2007) in which BGE identified Non-Compliance to Requirement 2 of Reliability Standard FAC-003-1;

b) Vegetation Outage Report (Submitted by BGE to Reliability*First* on August 20, 2007);

c) Vegetation Outage Questionnaire – [FAC-003], (Submitted by BGE to Reliability*First* on October 26, 2007)

d) Notice of Alleged Violation and Proposed Penalty or Sanction, (Issued by Reliability*First* to BGE on March 18, 2008)

e) Response to Notice of Alleged Violation and Proposed Penalty or Sanction, (Submitted by BGE to Reliability*First* on April 9, 2008)

f) Certificate of Completion of Mitigation Plan, (Submitted by BGE to Reliability*First* on March 31, 2008)

[6] *See* 18 C.F.R § 39.7(d)(5).

VII. Conclusion

Any questions regarding this Notice of Confirmed Violation and Proposed Penalty or Sanction issued by Reliability*First* should be directed to the undersigned.

Respectfully submitted,

Raymond J. Palmieri

Raymond J. Palmieri
Reliability*First* Corporation
Vice President and Director of Compliance

cc: NERC

David Hilt – NERC Vice President and Director of Compliance
Tim Kucey – NERC Manager of Enforcement and Mitigation

Reliability*First*

Tim Gallagher – President
Robert Wargo – Manager of Compliance Enforcement

Baltimore Gas and Electric Company

Ken DeFontes – President
Stephen J. Woerner – Senior Vice President, Electric Business Operations & Planning
Daniel Taormina – Transmission Compliance Consultant

Stephen J. Woerner, P.E.
Senior Vice President
Gas & Electric Operations & Planning

7309 Windsor Mill Road
Baltimore, Maryland 21244-2839
410.470.5280
443.213.3264 Fax

BGE

May 2, 2008

Mr. T. J. Kucey
Manager of Enforcement & Mitigation
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, New Jersey 08540

Re: Notice of Confirmed Violation, Docket No. RFC 200700002
Statement of Baltimore Gas and Electric Company

Dear Mr. Kucey:

Pursuant to Compliance Monitoring Enforcement Program Section 8.0, Baltimore Gas and Electric Company (BGE) submits this statement to the North American Electric Reliability Corporation (NERC) to accompany the Notice of Confirmed Violation (Notice) submitted to NERC by ReliabilityFirst Corporation (ReliabilityFirst) on April 28, 2008 in the referenced docket.

The vegetation related outage that is the subject of the Notice was timely detected, reported, and remedied without injury and without service interruption. BGE has long maintained an effective vegetation management program, and regrets even a single incident whereby any overgrowth leads to an outage. In order to more fully safeguard against any such reoccurrence, BGE's exhaustive vegetation management plan is now enhanced by the Mitigation Plan that ReliabilityFirst accepted and submitted for approval to NERC on February 15, 2008. The Mitigation Plan details the remedial measures undertaken, such as removing/trimming the trees in the immediate location where the outage occurred, conducting an inspection of all transmission lines over 200kV for any potential vegetation issues, contracting with a third party consulting company to independently review and confirm BGE's inspection, enhancing its training program, and designing clear mitigation measures for protection of transmission facilities for locations where BGE has been restricted from attaining the specified clearances.

Sincerely,

Stephen J. Woerner

cc: Raymond Palmieri, Vice President and Director of Compliance
ReliabilityFirst Corporation

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Attachment d

Mitigation Plan designated as MIT-07-0427

RELIABILITY FIRST

NERC ID RFC200700002

Proposed Mitigation Plan

Date Submitted: January 22, 2008

Registered Entity Information

Company Name: Baltimore Gas and Electric (BGE)

Company Address:

Electric Operations Building
7309 Windsor Mill Road
Baltimore, MD 21244

Mitigation Plan Contact Person & Phone Number:

Daniel Taormina
(410) 597-7593

Violation

Reliability Standard Number: FAC-003-1

Requirement Number Violated: R2

Cause of the Violation:

A vegetation contact occurred on Graceton to Raphael Road (BGE Transmission Circuit #2313) due to the presence of a tree in the pine family (Pinaceae Picea pungens) on the right of way between towers #86 and #87. The arc or contact occurred due to a failure to maintain appropriate clearance between the tree and the conductor at maximum emergency sag for a 230 kV transmission line.

Plan to Correct the Violation

1) The trees in the location where the vegetation contact occurred were removed or trimmed.

2) BGE Forestry personnel completed an inspection of all transmission lines over 200kV for any potential vegetation issues. Out of an abundance of caution, a very conservative approach was taken regarding vegetation on the transmission right of way (ROW) and BGE aggressively trimmed and /or removed trees within the ROW.

3) Establish and Implement a Training Program
BGE Transmission Engineering, Design & Standards created a comprehensive training program for communication of the requirements of the BGE Transmission Vegetation Management program. The training includes a review of the TVMP, expectations for BGE Forestry and contract personnel, guidance on Clearance 1 and Clearance 2 definitions, proper use and expectations for laser measuring devices, required use of and reading Plan & Profile drawings. The training has been held for Forestry personnel responsible for TVMP implementation on two occasions post the August 15, 2007 event and will be an annual requirement moving forward.

Plan to Prevent Recurrence of the Violation

1) The trees in the location where the vegetation contact occurred were removed or trimmed.

2) BGE Forestry personnel completed an inspection of all transmission lines over 200kV for any potential vegetation issues. Out of an abundance of caution, a very conservative approach was taken regarding vegetation on the transmission right of way (ROW) and BGE aggressively trimmed and /or removed trees within the ROW.

3) Establish and Implement a Training Program
BGE Transmission Engineering, Design & Standards created a comprehensive training program for communication of the requirements of the BGE Transmission Vegetation Management program. The training includes a review of the TVMP, expectations for BGE Forestry and contract personnel, guidance on Clearance 1 and Clearance 2 definitions, proper use and expectations for laser measuring devices, required use of and reading Plan & Profile drawings. The training has been conducted on two occasions post the August 15, 2007 event and will be an annual requirement moving forward.

4) Contract with an independent, third party consulting company to conduct vegetation inspection of the BGE Transmission System (200 kV and above) to confirm the completeness of the BGE Forestry inspection [as described in item #2 above], and document and catalog any vegetation management issues in the BGE Transmission ROW System (200 kV and above). Feedback from the consultant's findings will be incorporated into the BGE Transmission Vegetation Management Plan.

5) Implement and document clear mitigation measures for protection of transmission

RELIABILITY FIRST

facilities for locations where BGE has been restricted (through federal, state, or local rules, regulations and easements or BGE past practice) from attaining the clearances specified in Clearance 1 [as directed by FAC-003-1 R1.4].

6) Create a unique Annual Plan that is separate from, but consistent with, the requirements of the TVMP.

Mitigation Plan

Anticipated Impact of the Mitigation Plan on the Bulk Power System Reliability:

As noted in the "Plan to Correct the Violation" section, the trees in the area where the vegetation contact occurred were removed or trimmed. BGE Forestry personnel conducted an inspection of all BGE 200 kV and above ROW for potential vegetation issues and aggressively trimmed and / or removed trees. Furthermore, BGE contracted with an independent, third party consulting company to conduct a vegetation inspection of the BGE Transmission System (200 kV and above) to confirm the completeness of that inspection and to document and catalog any vegetation management issues in the BGE Transmission ROW System (200 kV and above). BGE will incorporate feedback from the consultant's findings into the TVMP. Additionally, classroom training has been conducted on two separate occasions to ensure proper implementation of the BGE TVMP, and will be an annual requirement going forward. Therefore, BGE submits that the risk to the reliability of the BGE Bulk Power System for FAC-003-1 has been mitigated.

Action Plan to Mitigate Any Increased Risk to the Reliability of the Bulk Power-System while the Mitigation Plan is Being Implemented:

The risk to the reliability of the BGE Bulk Power System for FAC-003-1 has been eliminated. Therefore, an Action Plan is not warranted.

RELIABILITY FIRST

Mitigation Plan Schedule

Anticipated Completion Date:

March 31, 2008

Implementation Milestones & Due Dates (no more than three (3) months apart):

The BGE "Plan to prevent recurrence of the violation" will be completed in its entirety by March 31, 2008.

Any Additional Information

The vegetation contact occurred at 1837 on August 15, 2007. BGE initiated mitigation efforts immediately following the vegetation contact. BGE Forestry conducted 100% field inspections of all 230 kV and 500kV right of way (ROW). Out of an abundance of caution in the wake of the August 15 outage, a very conservative approach was taken regarding vegetation on the transmission right of way (ROW) and BGE aggressively trimmed and/or removed trees within the ROW. This initial inspection and field work was completed by mid-September.

BGE Reliability and Compliance Assurance Unit (RCA) was notified of the event the morning of August 16, 2007. RCA and BGE Forestry notified BGE Senior Leadership of the vegetation contact and the potential violation to the NERC Reliability Standard and the BGE Transmission Vegetation Management Program. BGE RCA and Forestry were in contact with ReliabilityFirst on August 16th and 17th to notify the Regional Entity of the event and request guidance on the appropriate reporting requirements.

On Monday morning August 20th, 2007 at 0730 BGE conducted a formal meeting of Senior Leadership, Reliability and Compliance Assurance Unit, and BGE Forestry personnel. By the afternoon of August 22, 2007, a BGE Vegetation Management Investigation Team was formed sponsored by the Senior Vice-President of BGE Asset Management Services and Co-Sponsored by the Senior Vice-President of Electric Business Operations & Planning and the Senior Vice-President of Integrated Field Services. The Investigation Team consisted of a Team lead from Engineering and Standards and included members from Forestry, Project Management, and Reliability and Compliance Assurance. The team charter required a comprehensive review of BGE compliance to FAC-003-1, and resulted in the mitigation plan contained herein.

RELIABILITY FIRST

Signature Stephen J. Woerner Date 1/22/08

Name: STEPHEN J. WOERNER

Title: SENIOR VICE PRESIDENT
ELECTRIC BUSINESS OPERATIONS & PLANNING

Attachment e

Baltimore Gas & Electric Company's Certification of Completion of the Mitigation Plans

Stephen J. Woerner, P.E.
Senior Vice President
Electric Business Operations & Planning

7309 Windsor Mill Road
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410.597.6465 EOB-RBC
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stephen.j.woerner@bge.com

BGE

March 31, 2008

Mr. Raymond J. Palmieri
Vice President and Director of Compliance
ReliabilityFirst Corporation
320 Springside Drive, Suite 300
Akron, Ohio 44333

Re: **Docket No. RFC 200700002**
Baltimore Gas and Electric Company Certification of Completion of Mitigation Plan

Dear Mr. Palmieri:

This letter is to certify to ReliabilityFirst Corporation (ReliabilityFirst) that Baltimore Gas and Electric Company (BGE) has successfully completed the Mitigation Plan submitted to ReliabilityFirst on January 22, 2008 with respect to the referenced Docket. On February 15, 2008, that plan was accepted by ReliabilityFirst and sent to NERC for approval.

Background

On August 15, 2007, a vegetation contact occurred on BGE Transmission Circuit No. 2313. On August 20, 2007, BGE submitted to ReliabilityFirst a Vegetation Outage Report informing ReliabilityFirst of the outage and indicating that the cause of the outage was due to contact between a pine tree and a conductor. On that same day, BGE submitted a Self-reporting form identifying non-compliance with FAC-003-1, Requirement 2.

BGE's Proposed Mitigation Plan

On January 22, 2008, BGE submitted a Proposed Mitigation Plan in accordance with CMEP 6.2. In that Plan, BGE detailed its plans to correct the alleged violation and prevent its recurrence. Specifically, BGE noted that it remedied the situation causing the outage and planned to prevent further recurrences through the following actions:

- Removing or trimming the trees in the immediate location where the outage occurred;

- Conducting an inspection of all transmission lines over 200kV for any potential vegetation issues;

- Immediately establishing and implementing, as well as annually establishing and implementing, a training program for communication of the requirements of the BGE Transmission Vegetation Management Program (TVMP) including a review of the TVMP, expectations for BGE Forestry and contract personnel, guidance on Clearance 1 and Clearance 2 definitions, proper use and expectations for laser measuring devices, and required use of and reading Plan & Profile drawings;

- Contracting with an independent, third party consulting company to conduct a vegetation inspection of the BGE Transmission System (200 kV and above) to confirm the completeness of the BGE Forestry inspection, and document and catalog any vegetation management issues in the BGE Transmission System right-of-way (200 kV and above), and to incorporate the consultant's findings into BGE's TVMP;

- Implementing and documenting clear mitigation measures for protection of transmission facilities for locations where BGE has been restricted (through federal, state, or local rules, regulations and easements or BGE past practice) from attaining the clearances specified in Clearance 1 (as directed by FAC-003-1 R1.4); and

- Creating a unique Annual Plan that is separate from, but consistent with, the requirements of the TVMP.

This Mitigation Plan was accepted by ReliabilityFirst on February 15, 2008.

Certification of Completion

BGE has successfully completed all the elements as identified in its Mitigation Plan as of the date of this letter. This letter is executed by the undersigned, a corporate officer, and serves as the required certification that the Mitigation Plan is complete. If you have any additional questions, please do not hesitate to contact me.

Sincerely,

Stephen J. Woerner
Senior Vice President
Electric Business Operations & Planning

Attachment f

Reliability*First* Corporation's statement of verification that the Mitigation Plans have been successfully completed

RELIABILITY*FIRST*

June 2, 2008

Summary and Review of Evidence of Mitigation Plan Completion

NERC Violation ID #:	**RFC200700002**
NERC Plan ID:	**MIT-07-0427**
Registered Entity:	**Baltimore Gas and Electric Company**
Standard:	**FAC-003-1**
Requirement:	**2**
Status:	**Complete**

Review Process:

Baltimore Gas and Electric (BGE) certified that this Mitigation Plan was completed on March 31, 2008. Reliability*First* requested evidence of completion for actions taken by BGE as specified in the Mitigation Plan. BGE submitted supporting documentation to Reliability*First* on May 21, 2008. Reliability*First* reviewed the evidence submitted in a manner similar to a compliance audit to verify that all actions specified in the Mitigation Plan were successfully completed.

Evidence Provided:

BGE submitted photos of the location where the vegetation contact occurred (Transmission Circuit 2313). The photos show the area in the condition that existed at the time of contact, during clearing of vegetation after the contact, and after all vegetation work in the area was completed. The photos provided of the area after the vegetation work was completed indicate that the area was cleared of all high growth vegetation. BGE also provided completed work orders associated with the vegetation clearing work in the area of the vegetation contact.

BGE completed ground inspections of all transmission lines over 200 kV to identify any areas of potential concern for vegetation issues. BGE submitted completed work orders for all vegetation work completed in areas identified from the inspections as areas of potential concern.

BGE submitted a presentation and Agenda used in training sessions attended by Forestry and Transmission Engineering & Design Standards personnel that addressed vegetation issues on the transmission system. Sign-in sheets were also provided to document the personnel that attended the training sessions.

BGE submitted specifications provided to a consulting company contracted to perform work conducting inspections of the entire BGE Transmission System (200 kV and above) to confirm completeness of the BGE inspections previously described and to document any vegetation management issues that may present a concern within the next five years. A document was provided that presented the consultant's findings for incorporation into the BGE Transmission Vegetation Management Plan (TVMP).

BGE provided a list of mitigation measures developed for the protection of transmission facilities for locations where BGE access has been restricted (due to federal, state, local rules, or other issues). These measures are to be implemented on an on-going basis.

BGE submitted the current BGE TVMP with a revision history highlighting changes made since the vegetation contact in effort to improve future vegetation performance. BGE also created and submitted a unique annual plan consisting of vegetation maintenance schedules that incorporated the consulting company's findings. This annual plan supplements the requirements of the TVMP.

Review Results:

The Reliability*First* Compliance Staff has reviewed the evidence discussed above that was provided by BGE and determined, in their professional judgment, that BGE has submitted sufficient evidence to conclude BGE has completed the Mitigation Plan approved by Reliability*First* and NERC.

Respectfully Submitted,

Robert K. Wargo

Robert K. Wargo
Manager of Compliance Enforcement
Reliability*First* Corporation

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Attachment g

NERC BOTCC Decision

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Board of Trustees Compliance Committee
Decision on Notice of Penalty
(Issued May 21, 2008)

The North American Electric Reliability Corporation (NERC) Board of Trustees Compliance Committee approves for filing with the Federal Energy Regulatory Commission the following Notice of Penalty.

NOP ID	Regional Entity	Registered Entity	NOC ID	NERC Violation ID	Rel. Std.	Req. (R)	VRF	Total Penalty ($)
NOP-38	RFC	Baltimore Gas and Electric Company	NOC-55	RFC200700002	FAC-003-1	2	High	180,000

In the referenced Notice of Penalty, the Board of Trustees Compliance Committee approves the assessment of a financial penalty of $180,000 by Reliability*First* Corporation (RFC) against Baltimore Gas and Electric Company (BG&E) arising from BG&E's self-report of its failure to maintain, pursuant to NERC Reliability Standard FAC-003-1 R.2, the appropriate clearance between a tree and a conductor in accordance with its Vegetation Management Plan, which resulted in a 230 kV transmission line outage on August 15, 2007. The line was returned to service on August 16, 2007.

NERC stated its interpretation of the vegetation management standard during FERC's consideration of proposed FAC-003-1: A vegetation-related transmission line outage as a result of vegetation that has grown into the pre-defined clearance zone is a violation of the standard.[1] The Commission adopted that interpretation when it approved NERC's proposed reliability standards. It stated, "FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions."[2] Because violations of the Requirements 1 and 2 of FAC-003-1 could directly lead to or contribute to widespread outages or cascading failures, NERC assigned "high" violation risk factors to those requirements. NERC stated, "Clearly, the failure to have a vegetation management program with appropriate clearances, and an annual work plan could directly (and has) contribute to widespread outages."[3] The Commission confirmed that interpretation and understanding when it approved NERC's proposed violation risk factors for FAC-003-1, stating:

[1] *Comments of the North American Electric Reliability Council and the North American Electric Reliability Corporation on Staff Preliminary Assessment,* Docket No. RM06-16-000, filed June 26, 2006, p. 31.
[2] *Mandatory Reliability Standards for the Bulk-Power System,* FERC Stats. & Regs. ¶ 31,242 at P 729 (2007) (Order No. 693).
[3] *Request of the North American Electric Reliability Corporation for Approval of Supplemental Violation Risk Factors for Version 1 Reliability Standards,* Docket No. RR07-12-000 (May 4, 2007), at Exhibit A.

> With regard to FAC-003-1, Requirement R1 requires a transmission owner to develop a transmission vegetation management program, and Requirement R2 requires a transmission owner to implement the program. NERC's assignment of a "high" Violation Risk Factor to Requirements R1 and R2 is appropriate because inadequate vegetation management presents a serious risk of sustained transmission outage and could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures. Both planning and implementation are critical to vegetation management. A vegetation-related transmission outage would result in a violation of Requirement R1, R2 or both.[4]

In assessing this financial penalty, NERC and RFC considered the following: (1) There is no question that BG&E had a vegetation management plan and was implementing its plan; (2) BG&E was aware of the vegetation from prior patrols but allowed the vegetation to remain "because of resistance, for aesthetic reasons, by an adjacent property owner to the complete removal of trees from the site." The vegetation was scheduled to be removed on the next routine maintenance schedule in early 2008; (3) BG&E self-reported the vegetation and transmission line outage constituting the violation; (4) BG&E worked cooperatively with RFC; (5) BG&E acted immediately to mitigate and correct the violation; (6) The actions taken by BG&E ensure that reliability is maintained; and (7) BG&E accepted or did not contest the RFC findings of the violation or the proposed penalty.

Therefore, the NERC Board of Trustees Compliance Committee finds that the proposed penalty is appropriate and consistent with NERC's goal to ensure reliability of the bulk power system.

By the Board of Trustees Compliance Committee

[4] *North American Electric Reliability Corporation*, Order on Violation Risk Factors, 119 FERC ¶ 61,321 at P 10 (June 26, 2007).

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Attachment h

Notice of Filing

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Baltimore Gas & Electric Company   Docket No. NP08-___-000

NOTICE OF FILING
(DATE)

Take notice that on [DATE], the North American Electric Reliability Corporation (NERC) filed a Notice of Penalty regarding Baltimore Gas & Electric Company in the Reliability*First* Corporation region.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: [BLANK]

Kimberly D. Bose,
Secretary

EXHIBIT E

EXHIBIT E

for Tree Care Operations —

Tree, Shrub, and Other Woody Plant Maintenance — Standard Practices (Integrated Vegetation Management a. Electric Utility Rights-of-way)

ANSI A300 (Part 7)-2006 IVM

Approved American National Standard

ANSI

ANSI®
A300 (Part 7)-2006

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)*

Secretariat

Tree Care Industry Association, Inc.

Approved February 21, 2006

American National Standards Institute, Inc.
Headquarters:
1819 L Street, NW
Sixth Floor
Washington, DC 20036
New York Office:
25 West 43rd Street
Fourth Floor
New York, NY 10036

American National Standard

Approval of an American National Standard requires review by ANSI that the requirements for due process, consensus, and other criteria for approval have been met by the standards developer.

Consensus is established when, in the judgement of the ANSI Board of Standards Review, substantial agreement has been reached by directly and materially affected interests. Substantial agreement means much more than a simple majority, but not necessarily unanimity. Consensus requires that all views and objections be considered, and that a concerted effort be made toward their resolution.

The use of American National Standards is completely voluntary; their existence does not in any respect preclude anyone, whether he or she has approved the standards or not, from manufacturing, marketing, purchasing, or using products, processes, or procedures not conforming to the standards.

The American National Standards Institute does not develop standards and will in no circumstances give an interpretation of any American National Standard. Moreover, no person shall have the right or authority to issue an interpretation of an American National Standard in the name of the American National Standards Institute. Requests for interpretations should be addressed to the secretariat or sponsor whose name appears on the title page of this standard.

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Published by

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Printed in the United States of America

Contents

Foreword (This foreword is not part of American National Standard A300 Part 7-2006)

An industry-consensus standard must have the input of the industry that it is intended to affect. The Accredited Standards Committee A300 was approved June 28, 1991. The committee includes representatives from the residential and commercial tree care industry, the utility, municipal, and federal sectors, the landscape and nursery industries, and other interested organizations. Representatives from varied geographic areas with broad knowledge and technical expertise contributed.

The A300 standards are placed in proper context if one reads the Scope, Purpose, and Application. This document presents performance standards for the care and maintenance of trees, shrubs, and other woody plants. It is intended as a guide in the drafting of maintenance specifications for federal, state, municipal, and private authorities including property owners, property managers, and utilities.

The A300 standards stipulate that specifications for tree work should be written and administered by a professional possessing the technical competence to provide for, or supervise, the management of woody landscape plants. Users of this standard must first interpret its wording, then apply their knowledge of growth habits of certain plant species in a given environment. In this manner, the users ultimately develop their own specifications for plant maintenance.

ANSI A300 Part 7 – *Integrated Vegetation Management a. Electric Utility Rights-of-way*, should be used in conjunction with the rest of the A300 standard when writing specifications for tree care operations.

Suggestions for improvement of this standard should be forwarded to: A300 Secretary, c/o Tree Care Industry Association, 3 Perimeter Road – Unit 1, Manchester, NH 03103, USA or e-mail: tcia@treecareindustry.org

This standard was processed and approved for submittal to ANSI by Accredited Standards Committee on Tree, Shrub, and Other Woody Plant Maintenance Operations – Standard Practices, A300. Committee approval of the standard does not necessarily imply that all committee members voted for its approval. At the time it approved this standard, the A300 committee had the following members:

Tim Johnson, Chair
(Artistic Arborist, Inc.)
Bob Rouse, Secretary
(Tree Care Industry Association, Inc.)

Organizations Represented	*Name of Representative*
American Nursery and Landscape Association	*Warren Quinn*
	Craig J. Regelbrugge (Alt.)
American Society of Consulting Arborists	*Tom Mugridge*
	Donald Zimar (Alt.)
American Society of Landscape Architects	*Ron Leighton*
Asplundh Tree Expert Company	*Geoff Kempter*
	Peter Fengler (Alt.)
Bartlett Tree Expert Company	*Peter Becker*
	Dr. Thomas Smiley (Alt.)
Davey Tree Expert Company	*Joseph Tommasi*

	Dick Jones (Alt.)
International Society of Arboriculture	*Bruce Hagen*
	Sharon Lilly (Alt.)
National Park Service	*Robert DeFeo*
	Dr. James Sherald (Alt.)
Professional Landcare Network	*Preston Leyshon*
	Tanya Tolpegin (Alt.)
Professional Grounds Management Society	*Tom Shaner*
Society of Municipal Arborists	*Andrew Hillman*
	Tom Russo (Alt.)
Tree Care Industry Association	*Dane Buell*
	James McGuire (Alt.)
U.S. Forest Service	*Ed Macie*
	Keith Cline (Alt.)
Utility Arborist Association	*Matthew Simons*
	Jeffrey Smith (Alt.)

Additional organizations and individuals:

American Forests (Observer)
Beth Palys (Observer)
Peter Gerstenberger (Observer)
Mike Galvin (Observer)
Myron Laible (Observer)
Richard Rathjens (Observer)
Richard Roux (NFPA-780 Liaison)

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)*

Clause 1 excerpted from ANSI A300(Part 1) – 2001 Pruning

1 ANSI A300 standards

1.1 Scope

ANSI A300 standards present performance standards for the care and maintenance of trees, shrubs, and other woody plants.

1.2 Purpose

ANSI A300 standards are intended as guides for federal, state, municipal, and private authorities including property owners, property managers, and utilities in the drafting of their maintenance specifications.

1.3 Application

ANSI A300 standards shall apply to any person or entity engaged in the business, trade, or performance of repairing, maintaining, or preserving trees, shrubs, or other woody plants.

70 Part 7 – Integrated Vegetation Management (IVM) standards

70.1 Purpose

The purpose of this document is to provide standards for developing specifications to implement an integrated approach to management of vegetation.

70.2 Reasons for Integrated Vegetation Management (IVM)

The reason for Integrated Vegetation Management is to promote sustainable plant communities that are compatible with the intended use of the site, and discourage incompatible plants that may pose concerns, including safety, security, access, fire hazard, electric service reliability, emergency restoration, visibility, line-of-sight requirements, regulatory compliance, environmental, or other specific concerns.

70.3 Implementation

70.3.1 Specifications for integrated vegetation management should be written and administered by a vegetation manager.

70.3.2 IVM specifications shall be adhered to.

70.4 Safety

70.4.1 IVM shall be implemented by a qualified vegetation manager familiar with the practices and hazards of vegetation management and the equipment used in such operations.

70.4.2 This standard shall not take precedence over applicable industry safe work practices.

70.4.3 Operations shall comply with applicable Federal and State Occupational Safety and Health standards, ANSI Z133.1, FIFRA, Federal EPA, as well as state and local regulations.

71 Normative references

ANSI A300 *for Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices*

ANSI Z133.1 *Arboricultural Operations – Pruning, Repairing, Maintaining, and Removing Trees and Cutting Brush – Safety Requirements*

29 CFR 1910, *General Industry*

29 CFR 1910.268, *Telecommunications*

29 CFR 1910.269, *Electric Power Generation & Distribution*

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[1] *Available from U.S. Department of Labor, 200 Constitution Avenue, NW, Washington, DC 20210.*

29 CFR 1910.331-335, *Electrical Safety*

FIFRA (Federal Insecticide, Fungicide, and Rodenticide Act)

72 Definitions

72.1 action threshold: The maximum acceptable levels of plant density and height that initiates implementation of a control method.

72.2 biological control methods: Control of vegetation using plants, animals, insects, or pathogens.

72.3 chemical control methods: Control of vegetation through the use of herbicides, growth regulators, or other pesticides.

72.4 cultural control methods: Control of vegetation through the establishment of compatible stable plant communities or the use of crops, pastures, mulching, or other managed landscapes.

72.5 danger tree: A tree on or off the right-of-way that could contact electric supply lines.

72.6 electric supply lines: Conductors used to transmit electric energy and their necessary supporting and containing structures.

72.7 electric utility right-of-way: A corridor of land over which electric lines are located. The utility may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

72.8 hazard tree: A structurally unsound tree that could strike a target when it fails. As used in this clause the target of concern is electrical supply lines.

72.9 integrated vegetation management (IVM): 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. Choice of control methods is based on effectiveness, environmental impact, site characteristics, safety, security and economics.

72.10 maintenance cycle: Planned length of time between vegetation maintenance activities.

72.11 manual control method: Control of vegetation using hand-operated tools.

72.12 mechanical control methods: Control of vegetation using equipment-mounted saws, mowers, or other devices.

72.13 non-selective management: Methods used to control vegetation within a prescribed area without regard to retaining compatible vegetation.

72.14 right-of-way reclamation: Reestablishing IVM on a right-of-way that is not currently managed to the full extent of its easement or ownership rights and intended purpose. Conditions on a right-of-way in need of reclaiming include tall, dense amounts of undesirable vegetation, and electric supply lines that are inaccessible. Reclamation usually involves initial non-selective methods of mowing or hand-cutting, or broadcast application of herbicides.

72.15 selective management: Methods used to target specific vegetation within a prescribed area while retaining compatible vegetation.

72.16 shall: As used in this standard denotes a mandatory requirement.

72.17 should: As used in this standard denotes an advisory recommendation.

72.18 specifications: A document stating a detailed, measurable plan or proposal for provision of a product or service.

72.19 standards, ANSI A300: Performance parameters established by industry consensus as a rule for the measure of quantity, weight, extent, value, or quality.

72.20 vegetation, compatible: Vegetation that is desirable and/or suitable to the intended use of the site.

72.21 vegetation, incompatible: Vegetation that is undesirable, presents a safety hazard, or is unsuitable to the intended use of the site.

72.22 vegetation manager: An individual engaged in the profession of vegetation management who, through appropriate experience, education, and

[1)] *Available from U.S. Department of Labor, 200 Constitution Avenue, NW, Washington, DC 20210.*

related training, possesses the competence to provide for or supervise an integrated vegetation management program.

73 IVM a. Electric Utility Rights-of-way practices

73.1 IVM objectives

73.1.1 The vegetation manager (VM) shall define the objectives based on the intended purpose and use of the site.

73.1.2 The vegetation manager shall define action thresholds.

73.2 Site evaluations

73.2.1 The management area shall be inspected to evaluate existing conditions to determine if action thresholds have been met and what type of control method is necessary to meet the objectives.

73.2.2 Pre-control evaluations should include right-of-way use, type of electric supply line, general conditions, ownership, intended uses of the site, adjacent land use, existing vegetation, topography, soils, fire risk, sensitive or protected areas, water resources, sensitive or protected species, and regulations.

73.2.3 Vegetation that is compatible or incompatible with the objectives shall be identified.

73.2.4 Post-control evaluations should monitor efficacy and appropriateness of methods used, general site conditions, other impacts of treatments, and recommendations for future actions.

73.2.5 The results of site evaluations should be documented.

73.3 Management control method selection

73.3.1 Vegetation manager shall choose from available management control methods and implement appropriate methods.

73.3.2 Control methods selection should be based on pre-control evaluations, expected growth rates, electric supply line priority, economics, regulations, and specified objectives.

73.3.3 Efficacy of IVM control methods should be considered when scheduling implementation.

73.3.4 Control methods should promote compatible vegetation.

73.4 Communication

73.4.1 Communication with property owners, customers, and regulators regarding IVM activities should be proactive and shall be in compliance with federal, state, and local regulations.

74 IVM implementation

74.1 All laws, rules and regulations regarding public and worker safety shall be followed.

74.2 Specifications developed for IVM shall be adhered to.

74.3 Maintenance cycles should be based on existing vegetation, expected growth rates, and action thresholds.

74.4 Cultural control method

74.4.1 Over time and with successful implementation, cultural control methods should be preferred.

74.4.2 Cultural control methods should be considered for use once incompatible vegetation has been controlled.

74.5 Biological control method

This method should be considered for use once incompatible vegetation has been controlled.

74.6 Initial clearing of rights-of-way

74.6.1 When planning, designing, and constructing new rights-of-way, consideration should be given to future vegetation management needs.

74.6.2 When rights-of-way are being initially established, written easements should be secured defining rights to implement whatever IVM treatments are necessary to meet objectives.

74.7 Quality assurance

74.7.1 An IVM program should include a quality assurance program to ensure best practices are followed, objectives of IVM are met, and that all specifications are adhered to.

74.7.2 The results of IVM treatments and of the quality assurance program shall be clearly documented.

75 IVM applications

75.1 Tools and equipment

75.1.1 IVM equipment used to implement the program shall be in proper working condition.

75.1.2 Equipment shall be used according to manufacturers' instructions.

75.2 Chemical control application

75.2.1 Materials

75.2.1.1 Materials shall be used in accordance with federal, state, and local regulations.

75.2.1.2 Materials shall be applied according to manufacturers' labels.

75.2.1.3 Consideration should be given to utilizing products that minimize the risk to humans and the environment.

75.2.1.4 Consideration should be given to minimizing the amount of materials utilized over time to minimize the risk to humans and the environment.

75.2.1.5 Materials and methods should be selected to reduce the chance of developing resistance when the threat exists.

75.3 Selective management

75.3.1 The vegetation manager should employ selective management of vegetation whenever there is sufficient compatible vegetation actively growing on the right-of-way.

75.3.2 Where rights-of-way cross surface water resources, selective management should be utilized to create a buffer, retaining as much compatible vegetation as possible.

75.3.3 When incompatible vegetation with the potential for re-sprouting is manually-cleared, herbicide should be applied to the remaining stump.

75.4 Non-selective management

75.4.1 Right-of-way reclamation utilizing non-selective methods should be implemented as an initial step toward developing selective management on the site.

75.5 Mechanical methods

75.5.1 When performing right-of-way reclamation, mechanical clearing methods should be considered.

75.5.2 Where rights-of-way cross surface water resources, selective management should be utilized to create a buffer, retaining as much compatible vegetation as possible.

75.6 Tree pruning and tree removal

75.6.1 Tree pruning shall comply with ANSI A300 Part 1, section 5.9 – *Utility Pruning* standard.

75.6.2 Danger trees should be monitored, pruned, or removed as appropriate.

75.6.3 Trees identified as hazard trees should be pruned or removed as appropriate.

Annex A: Wire Zone – Border Zone Concept

The wire zone – border zone concept is a proven method that ensures the reliability of electric supply lines while promoting stable plant communities and wildlife habitat. Annex A provides supplemental information about this method.

A-1 Annex A Glossary

A-1.1 Border zone: An area on an electric utility right-of-way outside the wire zone, extending to the outer edge of the established right-of-way. Applies to electric utility rights-of-way only.

A-1.2 Wire zone: An area on an electric utility right-of-way directly beneath and between the energized conductors farthest out on the pole/tower. This area is the most likely to contain vegetation that could potentially grow into contact with the energized conductors. This area is also typically used as access to the poles, towers, and conductors for repair, inspection, and maintenance. Applies to electric utility rights-of-way only.

A-2 On electric utility rights-of-way, selective management may be implemented in the border zone whenever there is sufficient compatible vegetation.

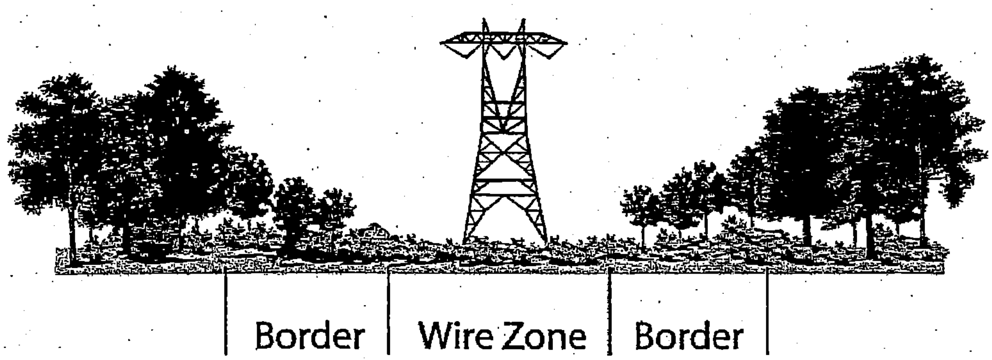


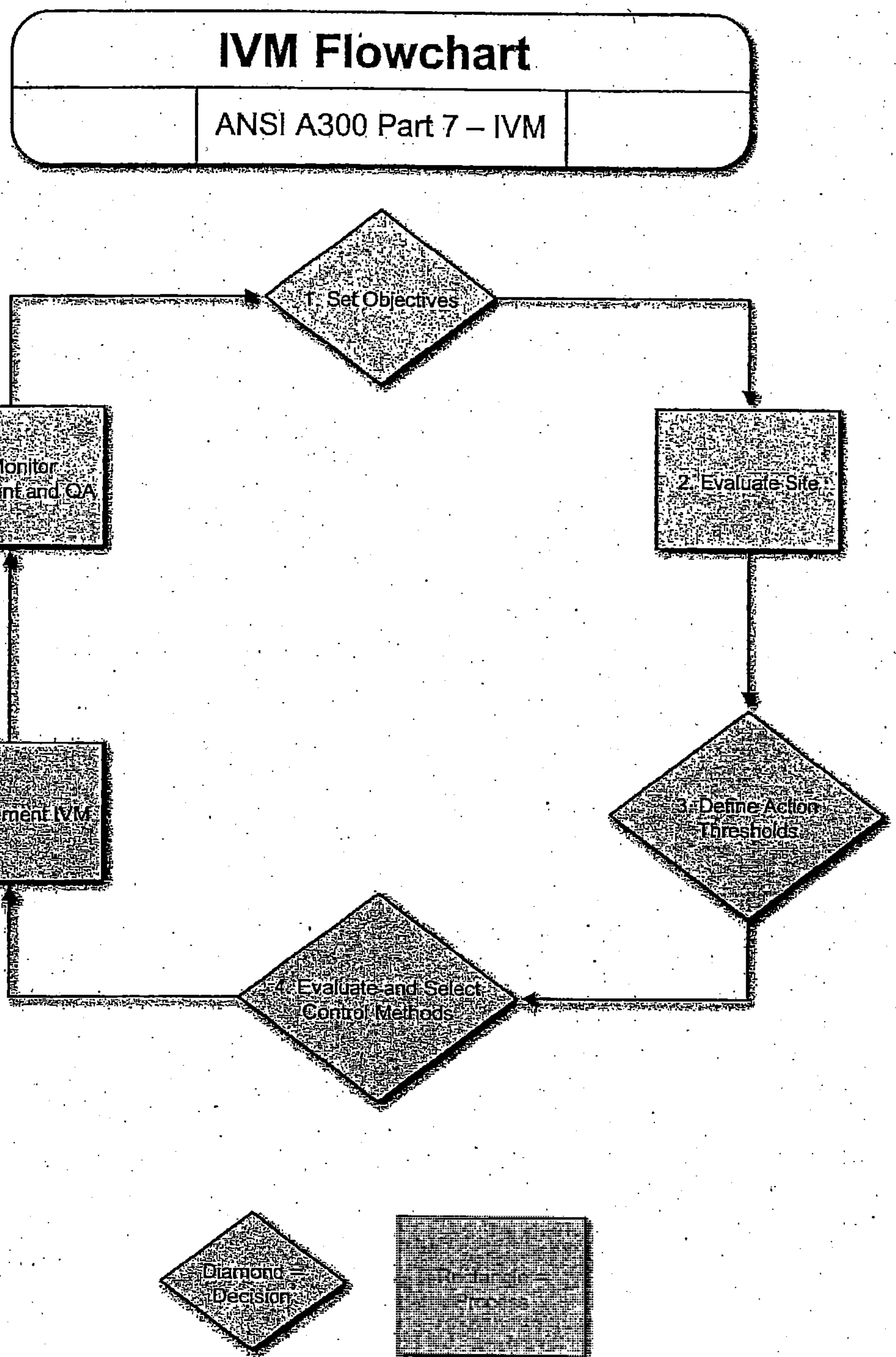
Figure 1: Wire Zone – Border Zone

A-3 On electric utility rights-of-way, non-selective management may take place in the wire zone of a right-of-way.

A-4 On rights-of-way that contain minimal or no compatible vegetation, or are very dense or not maintained, right-of-way reclamation by non-selective methods may be implemented in the border and wire zone.

Annex B: Integrated Vegetation Management Flow Chart

The following flow chart illustrates the IVM process as represented in the A300 Part 7 standard. Each element is explained in this standard.



Annex C: Applicable ANSI A300 interpretations

The following interpretations apply to the ANSI A300 Part 7 IVM standard.

A-1 Interpretation of "should" and "shall."

"An advisory recommendation" is the common definition of "should" used in the standards development community and the common definition of "should" used in ANSI standards. An advisory notice is not a mandatory requirement. Advisory recommendations may not be followed when defensible reasons for non-compliance exist.

EXHIBIT F

EXHIBIT F

TRANSMISSION CONTROL AGREEMENT

Among
The Independent System Operator
and
Transmission Owners

Tariff Record Proposed Effective Date: 11/23/10
Version Number: 0.0.0
Option Code: A

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Section

TRANSMISSION CONTROL AGREEMENT

APPENDIX C

ISO TRANSMISSION MAINTENANCE STANDARDS

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1. DEFINITIONS[1]

Availability - A measure of time a Transmission Line Circuit under ISO Operational Control is capable of providing service, whether or not it actually is in service.

Availability Measures - Within each Voltage Class in a calendar year: 1) the average Forced Outage(IMS) frequency for all Transmission Line Circuits, 2) the average accumulated Forced Outage(IMS) duration for only those Transmission Line Circuits with Forced Outages(IMS), and 3) the proportion of Transmission Line Circuits with no Forced Outages(IMS).

Availability Measure Targets - The Availability performance goals jointly established by the ISO and a PTO for that PTO's Transmission Facilities.

Forced Outage(IMS) – An event that occurs when a Transmission Facility is in an Outage(IMS) condition for which there is no Scheduled Outage(IMS) request in effect.

ISO Transmission Maintenance Standards - The Maintenance standards set forth in this Appendix C.

Maintenance - Maintenance as used herein, unless otherwise noted, encompasses inspection, assessment, maintenance, repair and replacement activities performed with respect to Transmission Facilities.

Maintenance Practices - A confidential description of methods used by a PTO, and adopted by the ISO, for the Maintenance of that PTO's Transmission Facilities.

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[1] A term followed by the superscript "(IMS)" denotes a term which has a special, unique definition in this Appendix C.

Maintenance Procedures – Documents developed by the Transmission Maintenance Coordination Committee for use by the ISO and the PTOs to facilitate compliance with the ISO Transmission Maintenance Standards. These documents shall serve as guidelines only.

Outage(IMS) - Any interruption of the flow of power in a Transmission Line Circuit between any terminals under ISO Operational Control.

PTO - A Participating TO as defined in Appendix D of the Transmission Control Agreement.

Scheduled Outage(IMS) - The removal from service of Transmission Facilities in accordance with the requirements of Section 7.1 of the Transmission Control Agreement and the applicable provisions of the ISO Tariff and ISO Protocols.

Station – Type of Transmission Facility used for such purposes as line termination, voltage transformation, voltage conversion, stabilization, or switching.

Transmission Facilities - All equipment and components transferred by a PTO to the ISO for Operational Control, pursuant to the Transmission Control Agreement, such as overhead and underground transmission lines, Stations, and associated facilities.

Transmission Line Circuit - The continuous set of transmission conductors, under the ISO Operational Control, located primarily outside of a Station, and apparatus terminating at interrupting devices, which would be isolated from the transmission system following a fault on such equipment.

Transmission Maintenance Coordination Committee ("TMCC") - The committee described in Section 7 of this Appendix C.

Voltage Class - The voltage to which operating, performance, and Maintenance characteristics are referenced. Voltage Classes are defined as follows:

Voltage Class	Range of Nominal Voltage
69 kV	≤ 70 kV
115 kV	110 - 161 kV
230 kV	200 - 230 kV
345 kV	280 - 345 kV
500 kV	500 kV
HVDC	HVDC

Capitalized terms, not expressly defined above, are used consistently with the definitions provided in the Transmission Control Agreement and the ISO Tariff.

2. INTRODUCTION

This Appendix C delineates the ISO Transmission Maintenance Standards and has been developed through a lengthy consensus building effort involving initially the ISO Maintenance Standards Task Force, and currently the TMCC.

Flexibility in establishing these ISO Transmission Maintenance Standards is implicit in the goal of optimizing Maintenance across a system characterized by diverse environmental and climatic conditions, terrain, equipment, and design practices. To provide for flexibility while ensuring the reasonableness of each PTO's approach to Maintenance, each PTO will prepare its own Maintenance Practices that shall be consistent with the requirements of these ISO Transmission Maintenance Standards. The effectiveness of each PTO's Maintenance Practices will be gauged through the Availability performance monitoring system. Each PTO's adherence to its Maintenance Practices will be assessed through an ISO review.

In developing these ISO Transmission Maintenance Standards, both the ISO Maintenance Standards Task Force and TMCC determined that it is impractical to develop and/or impose on the PTOs a single uniform set of prescriptive practices delineating conditions or time-based schedules for various Maintenance activities that account for the myriad of equipment, operating conditions, and environmental conditions within the ISO Controlled Grid. For this reason, these ISO Transmission Maintenance Standards provide requirements for the PTOs in preparing their respective Maintenance Practices.

2.1. OBJECTIVE

This Appendix C provides for a high quality, safe, and reliable ISO Controlled Grid by meeting the following objectives:

- Ensuring that the Availability performance levels inherent to the Transmission Facilities are maintained,
- Restoring Availability to the levels inherent to the Transmission Facilities when degradation has occurred,
- Economically extending the useful life of the Transmission Facilities while maintaining inherent levels of Availability, and
- Achieving the aforementioned objectives at a minimum reasonable total cost for Maintenance with the intent of minimizing customer impacts.

2.2. AVAILABILITY

ISO Controlled Grid reliability is a function of a complex set of variables, including accessibility of alternative paths to serve Load, Generating Unit availability, Load forecasting and resource planning; speed, sophistication and coordination of protection systems; and the Availability of Transmission Line

Circuits owned by the PTOs. Availability Measures have been chosen as the principal determinant of each PTO's Maintenance effectiveness.

When using Availability Measures as a general gauge of Maintenance effectiveness, several things must be considered to avoid misinterpreting performance. Availability is a function of several variables, including Transmission Facility Maintenance, initial design, extreme exposure, capital improvements, and improvements in restoration practices. These factors should be taken into account when assessing Availability Measures and Maintenance effectiveness. It is important to consider that Maintenance is one of many variables that impact changes in Availability. For example, certain Forced Outages(IMS) that impact Availability may be due to events that generally cannot be controlled by Maintenance.

If Availability Measures are either improving or declining, it is important to investigate the cause(s) and any trends that are causing change before drawing conclusions. If Maintenance is being performed by a PTO consistent with Good Utility Practice, increasing Maintenance activities by a significant order may not result in a corresponding increase in Availability and if Maintenance is not performed consistent with Good Utility Practice, Availability may decline. Thus, while Maintenance is important to ensure Availability, unless a PTO fails to perform Maintenance on a basis consistent with Good Utility Practice, significant increases in Maintenance activities will generally not lead to substantial improvements in Availability and associated ISO Controlled Grid reliability.

A variety of techniques can be used to monitor Maintenance effectiveness. However, techniques that do not account for random variations in processes have severe limitations in that they may yield inconsistent and/or erroneous assessments of Maintenance effectiveness. To account for random/chance variations while enabling monitoring for shifts and trends, control charts have been widely accepted and utilized. Control charts are statistically based graphs which illustrate both an expected range of performance for a particular process based on historical data, and discrete measures of recent performance. The relative positions of these discrete measures of recent performance and their relationship to the expected range of performance are used to gauge Maintenance effectiveness.

To enhance the use of Availability Measures as a gauge of Maintenance effectiveness, it is necessary to exclude certain types of Outages$^{(IMS)}$. These excluded Outages$^{(IMS)}$, as set forth in more detail in Section 4.1.3 of this Appendix C, are:

- Scheduled Outages$^{(IMS)}$;
- Outages$^{(IMS)}$ classified as "Not a Forced Outage" in the Maintenance Procedures;
- Forced Outages$^{(IMS)}$ caused by events originating outside the PTO's system; or
- Forced Outages$^{(IMS)}$ demonstrated to have been caused by earthquakes.

Additionally, as described in Section 4.1.2 of this Appendix C, the Forced Outage$^{(IMS)}$ duration used to calculate the Availability control charts has been capped at 72 hours so that excessively long Forced Outages$^{(IMS)}$ do not skew the data as to detract from the meaningfulness and interpretation of the control charts for accumulated Forced Outage$^{(IMS)}$ duration. This is not to say that an excessively long Forced Outage$^{(IMS)}$ is not a concern. Rather, such Forced Outages$^{(IMS)}$ should be investigated to assess the reasons for their extended duration.

Establishing Availability Measures requires each PTO to use separate control charts for each Voltage Class. Existing Forced Outage$^{(IMS)}$ data contains significant differences in the Availability between Voltage Classes and between PTOs. These differences may be attributable to factors such as the uniqueness of operating environments, Transmission Facility designs, and PTO operating policies. Regardless of the cause of these differences, review of the Forced Outage$^{(IMS)}$ data makes it eminently apparent that differences are such that no single set of control chart parameters for a particular Voltage Class could be applied to all PTOs.

Three types of control charts are utilized to provide a complete representation of historical Availability Measures, and to provide a benchmark against which future Availability Measures can be gauged. The three types of control charts for each PTO and Voltage Class are:

- The annual average Forced Outage$^{(IMS)}$ frequency for all Transmission Line Circuits;
- The annual average accumulated Forced Outage$^{(IMS)}$ duration for those Transmission Line Circuits which experience Forced Outages$^{(IMS)}$; and
- The annual proportion of Transmission Line Circuits that experienced no Forced Outages$^{(IMS)}$.

These three control charts assist the ISO and PTOs in assessing the Maintenance effectiveness of each Voltage Class over time. To accommodate this process on a cumulative basis, data is made available to the ISO by each PTO at the beginning of each new calendar year to assess past calendar years.

2.3. MAINTENANCE DOCUMENTATION REQUIREMENTS

Two specific requirements regarding Maintenance documentation are incorporated into these ISO Transmission Maintenance Standards. First, these standards require that each PTO develop and submit a description of its Maintenance Practices to the ISO. Second, these standards require that each PTO retain Maintenance records as set forth in Section 6.1 of this Appendix C and make those records available to the ISO as set forth in the Maintenance

Procedures, in order to demonstrate compliance with each element of its Maintenance Practices.

2.4. AVAILABILITY DATA STANDARDS

To facilitate processing Forced Outage$^{(IMS)}$ data for the Availability Measures, and to enable consistent and equitable interpretation of PTO Maintenance records by the ISO, these standards address the need for data recording and reporting. The TMCC has also developed standardized formats for transmitting Forced Outage$^{(IMS)}$ data to the ISO for the Availability Measures. These standard formats are provided in the Maintenance Procedures. To facilitate review of the data by the ISO, the TMCC has developed a standard Availability Measures reporting system detailed in the Maintenance Procedures and in Section 4 of this Appendix C. This system will provide for consistent gathering of information that can be used as the basis for analyzing Availability Measures trends.

3. FACILITIES COVERED BY THESE ISO TRANSMISSION MAINTENANCE STANDARDS

The ISO Transmission Maintenance Standards set forth in this Appendix C shall apply to all Transmission Facilities. Each PTO shall maintain its Transmission Facilities in accordance with its Maintenance Practices as adopted by the ISO in accordance with these ISO Transmission Maintenance Standards.

4. AVAILABILITY MEASURES

4.1. CALCULATION OF AVAILABILITY MEASURES FOR INDIVIDUAL TRANSMISSION LINE CIRCUITS

4.1.1 FREQUENCY AND DURATION

The calculation of the Availability Measures will be performed utilizing Forced Outage(IMS) data through December 31st of each calendar year. Separate Forced Outage(IMS) frequency and accumulated Forced Outage(IMS) duration Availability Measures shall be calculated as follows for each Transmission Line Circuit under ISO Operational Control within each Voltage Class. The calculations shall be performed annually for each of the Transmission Line Circuits utilizing all appropriate Forced Outage(IMS) data for the calendar year in question.

<u>Forced Outage(IMS) Frequency:</u>

The Forced Outage(IMS) frequency (f_{ik}) of the i^{th} Transmission Line Circuit shall equal the total number of Forced Outages(IMS) that occurred on the i^{th} Transmission Line Circuit during the calendar year "k". See Notes 1 and 2.

NOTES:

1. Multiple momentary Forced Outages(IMS) on the same Transmission Line Circuit in the span of a single minute shall be treated as a single Forced Outage(IMS) with a duration of one minute. When the operation of a Transmission Line Circuit is restored following a Forced Outage(IMS) and the Transmission Line Circuit remains operational for a period exceeding one minute, i.e., 61 seconds or more, followed by another Forced Outage(IMS), then these should be counted as two Forced Outages(IMS). Multiple Forced Outages(IMS) occurring as a result of a single event should be handled as multiple Forced Outages(IMS) only if subsequent operation of the Transmission Line Circuit between events exceeds one minute. Otherwise they shall be considered one continuous Forced Outage(IMS).

2. If a Transmission Line Circuit, e.g., a new Transmission Line Circuit, is only in service for a portion of a calendar year, the Forced Outage(IMS) frequency and accumulated duration data shall be treated as if the Transmission Line Circuit had been in service for the entire calendar year, i.e., the Forced Outage(IMS) data for that Transmission Line Circuit shall be handled the same as those for any other Transmission Line Circuit.

Accumulated Forced Outage$^{(IMS)}$ Duration:

The accumulated Forced Outage$^{(IMS)}$ duration in minutes shall be calculated as follows for each of the Transmission Line Circuits having a Forced Outage$^{(IMS)}$ frequency (f_{ik}) greater than zero for the calendar year "k":

$$d_{ik} = \sum_{j=1}^{f_{ik}} o_{ijk}$$

where

d_{ik} = accumulated duration of Forced Outages$^{(IMS)}$ (total number of Forced Outage$^{(IMS)}$ minutes) for the "ith" Transmission Line Circuit having a Forced Outage$^{(IMS)}$ frequency (f_{ik}) greater than zero for the calendar year "k".

f_{ik} = Forced Outage$^{(IMS)}$ frequency as defined above for calendar year "k".

o_{ijk} = duration in minutes of the "jth" Forced Outage$^{(IMS)}$ which occurred during the "kth" calendar year for the "ith" Transmission Line Circuit. See Notes 1 and 2.

The durations of extended Forced Outages$^{(IMS)}$ shall be capped as described in Section 4.1.2 of this Appendix C for the purposes of calculating the Availability Measures. In addition, certain types of Outages$^{(IMS)}$ shall be excluded from the calculations of the Availability Measures as described in Section 4.1.3 of this Appendix C.

If a PTO makes changes to its Transmission Line Circuit identification, configuration, or Forced Outage$^{(IMS)}$ data reporting schemes, the PTO shall notify the ISO at the time of the change. In its annual report to the ISO, the PTO shall provide recommendations regarding if and how the Availability Measures and Availability Measure Targets should be modified to ensure that they (1) remain consistent with the modified Transmission Line Circuit identification or Forced

Outage(IMS) data reporting scheme, and (2) provide an appropriate gauge of Availability.

4.1.2. CAPPING FORCED OUTAGE(IMS) DURATIONS

The duration of each Forced Outage(IMS) which exceeds 72 hours (4320 minutes) shall be capped at 4320 minutes for the purpose of calculating the accumulated Forced Outage(IMS) duration.

4.1.3. EXCLUDED OUTAGES (IMS)

The following types of Outages(IMS) shall be excluded from the calculation of the Availability Measures and the Availability Measure Targets:

- Scheduled Outages(IMS)
- Outages(IMS) classified as "Not a Forced Outage" in the Maintenance Procedures.

- Forced Outages(IMS) which: (1) were caused by events outside the PTO's system including Outages(IMS) which originate in other TO systems, other electric utility systems, or customer equipment, or (2) are Outages(IMS) which can be demonstrated to have been caused by earthquakes.

4.2. AVAILABILITY MEASURE TARGETS

The Availability Measure Targets described herein shall be phased in over a period of five calendar years beginning on the date a Transmission Owner becomes a PTO in accordance with the provisions of the Transmission Control Agreement. The adequacy of each PTO's Availability Measures shall be monitored through the use of charts. These charts, called control charts as shown in Figure 4.2.1, are defined by a horizontal axis with a scale of calendar years and a vertical axis with a scale describing the expected range of magnitudes of the index in question. Annual performance indices shall be plotted on these charts and a series of tests may then be performed to assess the stability of annual performance, shifts in performance and longer-term performance trends.

Control charts for each of the following indices shall be developed and utilized to monitor Availability Measures for each Voltage Class within each PTO's system:

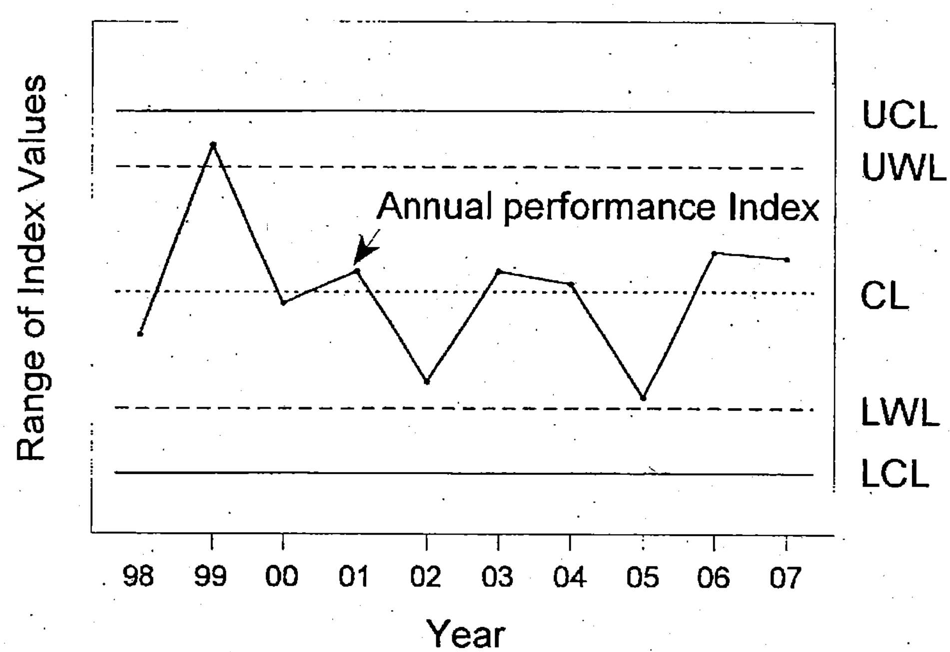

Figure 4.2.1 Sample Control Chart

- Index 1: Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits.
- Index 2: Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS).

- Index 3: Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS).

The control charts incorporate a center control line (CL), upper and lower control limits (UCL and LCL, respectively), and upper and lower warning limits (UWL and LWL, respectively). The CL represents the average annual historical performance for a period prior to the current calendar year. The UCL and LCL define a range of expected performance extending above and below the CL. For the annual proportion of Transmission Line Circuits with no Forced Outages(IMS), the limits are based on standard control chart techniques for binomial proportion data. For the other two indices, bootstrap resampling techniques are used to determine empirical UCL and LCL at 99.75% and 0.25% percentile values, respectively, for means from the historical data. The bootstrap procedure is described in Section 4.2.2 of this Appendix C. Similarly, the UWL and LWL define a range of performance intending to cover the percentiles from 2.5% to 97.5%. The bootstrap algorithm is also used to determine these values. Thus, the UCL and LCL will contain about 99.5% of resampling means from the Voltage Class of interest. UWL and LWL will contain about 95% of the resampling means. These limits coincide with the usual choices for control charts when the means are approximately normal. Bootstrap estimation procedures are used here since the sampling means do not follow the normal distribution model. The bootstrap estimation procedures ensure consistent control chart limits by using a starting base number ("seed") for its random number generator. Accuracy or reduced variances in the control chart limits are attained by using the average control chart limits generated from applying ten repetitions or cycles of the bootstrap sampling method. Collectively, the CL, UCL, LCL, UWL and LWL provide reference values for use in evaluating performance as described in Section 4.2.3 of this Appendix C.

For the special case where there is a Voltage Class with only one Transmission Line Circuit, individual and moving range control charts should be used for Index 1 and 2. The method used herein for calculating Index 3 is not applicable for those Voltage Classes containing less than six Transmission Line Circuits. The Maintenance Procedures will be used by the PTOs to calculate Index 1, 2, or 3 where the methods provided herein do not apply. More information on the individual and moving range control charts can be found in the user manuals of the statistical software recommended by the TMCC and approved by the ISO Governing Board for use in creating the control charts.

4.2.1. CALCULATIONS OF ANNUAL AVAILABILITY MEASURES INDICES FOR INDIVIDUAL VOLTAGE CLASSES

Separate annual Availability Measures indices shall be calculated for each Voltage Class and each PTO as described below by utilizing the calculations discussed in Section 4.1 of this Appendix C.

Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits (Index 1):

$$F_{vc,k} = \frac{1}{N_k}\sum_{i=1}^{N_k} f_{ik}$$

where

$F_{vc,k}$ = frequency index for the Voltage Class, vc, (units = Forced Outages(IMS)/Transmission Line Circuit). The frequency index equals the average (mean) number of Forced Outages(IMS) for all Transmission Line Circuits within a Voltage Class for the calendar year "k".

N_k = number of Transmission Line Circuits in Voltage Class in calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

f_{ik} = frequency of Forced Outages(IMS) for the "ith" Transmission Line Circuit as calculated in accordance with Section 4.1.1 of this Appendix C for calendar year "k".

Annual Average Accumulated Forced Outage$^{(IMS)}$ Duration for those Transmission Line Circuits with Forced Outages$^{(IMS)}$ (Index 2):

$$D_{vc,k} = \frac{1}{N_{o,k}} \sum_{i=1}^{N_{o,k}} d_{ik}$$

where

$D_{vc,k}$ = duration index for the Voltage Class (units = minutes/Transmission Line Circuit). The duration index equals the average accumulated duration of Forced Outages$^{(IMS)}$ for all Transmission Line Circuits within a Voltage Class which experienced Forced Outages$^{(IMS)}$ during the calendar year "k".

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.1.1 of this Appendix C is greater than zero for the calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

d_{ik} = accumulated duration of Forced Outages$^{(IMS)}$ for the "ith " Transmission Line Circuit having a Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) greater than zero for calendar year "k" as calculated in accordance with Section 4.1.1 of this Appendix C.

Annual Proportion of Transmission Line Circuits with No Forced Outages$^{(IMS)}$ (Index 3):

$$P_{vc,k} = \frac{N_k - N_{o,k}}{N_k}$$

where

$P_{vc,k}$ = index for the proportion of Transmission Line Circuits for the Voltage Class with no Forced Outages$^{(IMS)}$ for the calendar year "k".

N_k = number of Transmission Line Circuits in Voltage Class for calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.1.1 of this Appendix C is greater than zero for the calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

4.2.2. DEVELOPMENT OF LIMITS FOR CONTROL CHARTS

The CL, UCL, LCL, UWL and LWL for the three control charts (Annual Average Forced Outage$^{(IMS)}$ Frequency for All Transmission Line Circuits; Annual Average Accumulated Forced Outage$^{(IMS)}$ Duration for those Transmission Line Circuits with Forced Outages$^{(IMS)}$; and Annual Proportion of Transmission Line Circuits with No Forced Outages$^{(IMS)}$) on which the annual Availability Measures indices are to be plotted shall be calculated as described below. The CL, UCL, LCL, UWL and LWL for each of the three control charts shall be determined using continuously recorded Forced Outage$^{(IMS)}$ data for the ten calendar year period immediately preceding the date a Transmission Owner becomes a PTO in accordance with the provisions of the Transmission Control Agreement.

In the event that a PTO does not have reliable, continuously recorded Forced Outage$^{(IMS)}$ data for this 10 calendar year period, that PTO may determine the control chart limits using data for a shorter period. However, if data for a shorter period are to be used, that PTO shall prepare a brief report to the ISO providing reasonable justification for this modification. This report shall be submitted to the ISO within 90 days after the date a TO becomes a PTO in accordance with the provisions of the Transmission Control Agreement.

The ISO shall periodically review the control chart limits and recommend appropriate modifications to each PTO in accordance with this Appendix C.

4.2.2.1. CENTER CONTROL LINES (CLs)

The calculation of the CLs for each of the three control charts is similar to the calculation of the annual Availability Measures indices described in Section 4.2.1 of this Appendix C except that the time period is expanded from a single calendar year to ten calendar years, unless a shorter period is justified by a PTO, for the period preceding the date a TO becomes a PTO in accordance with the provisions of the Transmission Control Agreement. To account for this change, a count of Transmission Line Circuit years is included in the equations as shown below to enable derivation of CLs which represent average performance during a multi-year period.

<u>CL for Annual Average Transmission Line Circuit Forced Outage$^{(IMS)}$ Frequency</u>

$$CL_{fvc} = \sum_{k=1}^{Y}\sum_{i=1}^{N_k} f_{ik} \,/\, (\sum_{k=1}^{Y} N_k)$$

where

CL_{fvc} = center control line value for the Forced Outage$^{(IMS)}$ frequencies for each of the Transmission Line Circuits in the Voltage Class for "*Y*" calendar years prior to the date a TO becomes a PTO.

Y = number of calendar years prior to the date a TO becomes a PTO for which the PTO has reliable, continuously recorded Forced Outage$^{(IMS)}$ data. Y=10 is preferred.

<u>CL for Annual Average Accumulated Forced Outage$^{(IMS)}$ Duration for those Transmission Line Circuits with Forced Outages$^{(IMS)}$</u>

$$CL_{dvc} = \sum_{k=1}^{Y}\sum_{i=1}^{N_{o,k}} d_{ik} \,/\, (\sum_{k=1}^{Y} N_{o,k})$$

where

CL_{dvc} = center control line value for accumulated Forced Outage$^{(IMS)}$ duration for each of the Transmission Line Circuits in the Voltage Class for "*Y*" calendar years prior to the date a TO becomes a PTO in which the Forced Outage(IMS) frequency (f_{ik}) was greater than zero.

<u>CL for Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)</u>

$$CL_{Pvc} = \frac{\sum_{k=1}^{Y}(N_k - N_{o,k})}{\sum_{k=1}^{Y} N_k}$$

where

CL_{Pvc} = center control line value for the proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages(IMS) for "*Y*" calendar years prior to the date a TO becomes a PTO.

4.2.2.2. UCLs, LCLs, UWLs AND LWLs

<u>UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for Voltage Classes Containing Four or More Transmission Line Circuits with Forced Outages(IMS) for Five or More Calendar Years</u>

The UCLs, UWLs, LWLs, and LCLs for the control charts for each Voltage Class containing four or more Transmission Line Circuits with Forced Outages(IMS) shall be determined by bootstrap resampling methods as follows: The available historical data for Index 1 and 2 will each be entered into columns. A "seed" is then selected prior to beginning the sampling process. The ISO assigns a number for the "seed" prior to each calendar year's development of the control charts. The "seed" allows the user to start the sampling in the same place and get the same results provided the data order hasn't changed. For Index 1, sampling with replacement will occur for the median number of Transmission Line Circuits per calendar year in a Voltage Class for the time period being evaluated. A sample, the size of which is the median number of all Transmission Line Circuits for the period being evaluated, is taken from the column of actual frequency values for all Transmission Line Circuits. A mean is calculated from this sample and the resulting number will be stored in a separate column. This process will be repeated 10,000 times in order to create a column of sampling means from the historical database. The column of sampling means is then ordered from the smallest to largest means. From this column percentiles are determined for a UCL (99.75), a LCL (0.25), a UWL (97.5), and a LWL (2.5). Thus, for one cycle, the limits are determined by resampling from the historical database, calculating statistics of interest, in this case means, and then estimating appropriate limits from the resampling means. Ten cycles of this same process are necessary to get ten values each of UCLs, LCLs, UWLs, and LWLs. The average for the ten values of each limit is taken to provide the UCL, LCL, UWL, and LWL values used in analyzing annual performance. The procedure is repeated for Index 2, forming means for the median number of Transmission Line Circuits with Forced Outages(IMS) in this Voltage Class for the time period being evaluated. See **Bootstrapping - A Nonparametric Approach to Statistical Inference** (1993) by Christopher Z. Mooney and Robert D. Duval, Sage Publications with ISBN 0-8039-5381-X, and **An Introduction to the Bootstrap** (1993) by Bradley Efron and Robert J. Tibshirani, Chapman and Hall Publishing with ISBN 0-412-04231-2 for further information.

Consider an example to illustrate how the bootstrap procedure works for one cycle of the ten required. Assume that a Voltage Class has approximately 20 Transmission Line Circuits per calendar year with a history of ten calendar years. Furthermore, assume that about 15 Transmission Line Circuits per calendar year experience Forced Outages(IMS). Therefore, there are 10 x 15 = 150 Forced Outage(IMS) durations available for bootstrap sampling. Place these 150 Forced Outage(IMS) durations in a column, say "outdur," in a specified order. The order is automatically provided in the bootstrap algorithm developed by the ISO and made available to the PTO. The bootstrap algorithm will sample 15 rows from "outdur" with replacement. That is, any row may, by chance, be sampled more than once. From these 15 values determine the sample mean and place this in another column, say "boot". Repeat this sampling process 10,000 times adding the new means to "boot". The column "boot" now has 10,000 means from samples of size 15 from the original Forced Outage$^{(IMS)}$ duration data for this Voltage Class. The next step is to locate the appropriate percentiles from these means for use in determining the control chart limits for one cycle. This is accomplished by ordering the column "boot" from smallest-to-largest mean and restoring these ordered means in "boot". The percentiles which are needed are 99.75% (UCL), 97.50% (UWL), 2.50% (LWL) and 0.25% (LCL). These are easily estimated from the sorted means by finding the associated rows in the column "boot". For example, LWL will be estimated as the average of the 250th and 251st rows in column "boot". Likewise the other limits will be determined. Of course, the CL is the actual mean average for 15 Transmission Line Circuits over the ten calendar years using the formulas in Section 4.2.2.1 of this Appendix C. This example is for one cycle. Nine more cycles of this process will establish the more accurate control and warning limits necessary to evaluate a PTO's annual performance.

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for All Other Voltage Classes

When data for less than four Transmission Line Circuits with Forced Outages$^{(IMS)}$ are available per calendar year in a Voltage Class for fewer than five calendar years, an exhaustive enumeration of all possible selections with replacement may need to be performed. This is because the number of possible samples for bootstrap resampling will be less than the aforementioned 10,000 resampling frequency used for Voltage Classes containing four or more Transmission Line Circuits with Forced Outages$^{(IMS)}$ for five or more calendar years. For example, if a Voltage Class has only two Transmission Line Circuits per calendar year for five calendar years, the data base will consist of 2*5 = 10 accumulated Forced Outage$^{(IMS)}$ durations assuming both Transmission Line Circuits experience one Forced Outage$^{(IMS)}$ or more per calendar year. Resampling two values from the column of ten yields only 10**2 = 100 possible means. Thus, bootstrap resampling of 10,000 would over-sample the original data 10,000/100 = 100 times.

For the general case, let M = the number of accumulated Forced Outage(IMS) durations (or Forced Outage(IMS) frequencies) from the historical database. If n is the median number of Transmission Line Circuits per calendar year, there are M**n = U possible enumerated means for this Voltage Class. The procedure to determine the appropriate limits for a Voltage Class is to order the column containing "U" enumerated means from smallest to largest means. Then, the UCL, LCL, UWL, and LWL are determined from this vector as described above (i.e., at the 99.75, 0.25, 97.5, and 2.5 percentiles, respectively).

UCLs, LCLs, UWLs and LWLs for Index 3 When Number of Transmission Line Circuits is > 125

According to standard procedures for proportion control charts for Voltage Classes where the median number of Transmission Line Circuits in service is greater than 125 for any given calendar year, the upper and lower control chart limits (UCL, LCL, UWL, and LWL) for the "k^{th}" calendar year are determined using the normal approximation to the binomial distribution. The formulas are:

$$UCL = CL_{Pvc} + 3S_{Pvc,k} \qquad\qquad LCL = CL_{Pvc} - 3S_{Pvc,k}$$

UWL and LWL are calculated by replacing the "3" above with "2".

and

$$S_{Pvc,k} = \sqrt{CL_{Pvc}(1-CL_{Pvc})/N_k}$$

where

$S_{Pvc,k}$ = standard deviation for the annual proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages(IMS) for each "k^{th}" year of the "Y" calendar years prior to the date a TO becomes a

PTO. If LCL or LWL is less than zero, they should be set to zero by default.

UCLs, LCLs, UWLs and LWLs for Index 3 when Number of Transmission Line Circuits is less than or equal to 125 and greater than or equal to six

The UCLs, LCLs, UWLs, and LWLs for the control charts for each Voltage Class shall be based on exact binomial probabilities for those Voltage Classes having equal to or more than six, but less than or equal to 125 median Transmission Line Circuits per calendar year. A customized macro and a statistical software package approved by the ISO creates the proportion control charts. The macro determines the control limits and use of the exact binomial or the normal approximation to the binomial for computing the control chart limits. This macro ensures the UCL and LCL contain about 99.5% and the UWL and LWL contain about 95% of the binomial distribution. The percentile values of the UCL, UWL, LWL, and LCL are respectively 99.75%, 97.5%, 2.5%, and 0.25%.

The UCL, UWL, LWL, and LCL are calculated using the following formulas:

$$\mathbf{UCL} = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$\mathbf{UWL} = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$\mathbf{LWL} = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$\mathbf{LCL} = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

Where

P_1 = A cumulative binomial probability that if not equal to the P_2 value is representing the percentile value that is less than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if $P_1 = 0.99529$ and is closest to the 99.75 percentile value, from the low side, $P_1 = 0.99529$ should be used in the UCL formula).

P_2 = A cumulative binomial probability equal to the 0.9975, 0.9750, 0.025, and 0.0025 values used respectively in the UCL, UWL, LWL, and LCL above formulas (e.g., P_2 = 0.9975 in the UCL formula and = 0.025 in the LWL formula).

P_3 = A cumulative binomial probability that if not equal to the P_2 value is representing the percentile value that is greater than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if P_3 = 0.99796 and is closest to the 99.75 percentile value, from the high side, then P_3 = 0.99796 should be used in the UCL formula).

X_1 = The number of Transmission Line Circuits with no Forced Outages^(IMS) associated with the P_1 cumulative binomial probability values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if P_1 = 0.99529 and represents the closest percentile from below the 99.75 percentile for the case where 19 Transmission Line Circuits had no Forced Outages^(IMS), then X_1 = 19 should be used in the UCL formula).

n = The median number of Transmission Line Circuits that are in service in a given calendar year. This number remains the same in each of the UCL, UWL, LWL, and LCL formulas.

4.2.3. EVALUATION OF AVAILABILITY MEASURES PERFORMANCE

The control charts shall be reviewed annually by the ISO and PTOs in order to evaluate Availability Measures performance. The annual evaluation shall consist of an examination of each of the control charts to determine if one or more of the following four tests indicate a change in performance. The four tests have been selected to enable identification of exceptional performance in an individual calendar year, shifts in longer-term performance, and trends in longer-term performance.

<u>**Tests**</u>

- **Test 1:** The index value for the current calendar year falls outside the UCL or LCL.

- **Test 2:** At least v1 consecutive annual index values fall above the CL or v2 consecutive annual index values fall below the CL. The actual values of v1 and v2 will be output from the bootstrap resampling procedures. The choices for v1 and v2 are designed to keep the probability of these events less than one percent.

Table 1. Values of v1 and v2 for Percentiles of the CL in Specified Ranges

Percentile	v1	v2
35 - 39	10	5
40	10	6
41 - 43	9	6
44 - 46	8	6
47 - 48	8	7
49 - 51	7	7
52 - 53	7	8
54 - 56	6	8
57 - 59	6	9
60	6	10
61 - 65	5	10

Thus, for example, if for a particular Voltage Class the percentile of the historical CL is 55%, this Table indicates that the CL is located at the 55 percentile of all bootstrap means in the "boot" column. From Table 1, v1=6, and v2=8.

- **Test 3:** At least two out of three consecutive annual index values fall outside the UWL or LWL on the same side of the CL.
- **Test 4:** Six or more values are consecutively increasing or consecutively decreasing.

Therefore, Test 1 is designed to detect a short-term change or jump in the average level. Tests 2 and 4 are looking for long-term changes. Test 2 will detect a shift up in averages or a shift to a lower level. Test 4 is designed to detect either a trend of continuous increase in the average values or continuous decrease. Test 3 is designed to assess changes in performance during an intermediate period of three calendar years. If Test 3 is satisfied, the evidence is of a decline (or increase) in Availability over a three calendar year period. Together the four tests allow the ISO to monitor the Availability performance of a Voltage Class for a PTO.

If none of these tests indicate that a change has occurred, performance shall be considered to be stable and consistent with past performance. If one or more of these tests indicates a change then Availability performance shall be considered as having improved or degraded relative to the performance defined by the control chart. Table 4.2.1 provides a summary of the performance indications provided by the tests. The control chart limits may be updated annually if the last calendar year's Availability performance indices did not trigger any of the four tests. If none of the four tests are triggered, the new limits will be constructed including the last calendar year's data.

The control chart limits may be modified each year to reflect the number of Transmission Line Circuits in service during that calendar year if necessary. However, it is suggested that unless the number of Transmission Line Circuits changes by more than 30% from the previous calendar year, the use of the median number of Transmission Line Circuits should continue. Consider an example; suppose after the control chart has been prepared for a Voltage Class, next calendar year's data arrives with the number of Transmission Line Circuits 30% higher than the median used in the past. New limits will be generated in order to assess the Availability performance for that calendar year.

For the special case where only one Transmission Line Circuit has a Forced Outage$^{(IMS)}$ in a Voltage Class during a calendar year, the assessment process for Index 2 is as follows; if Index 2 for this Transmission Line Circuit does not trigger any of the four tests, no further action is necessary. If, however, one or more of the tests are triggered, then limits for this Transmission Line Circuit for that calendar year should be recalculated based on the historical data for this Transmission Line Circuit alone using an individual and moving range control chart. The only test warranted here is Test 1. More information on the individual and moving range control charts can be found in the user manuals of the statistical software used in creating the control charts

Table 4.2.1 Performance Indications Provided by Control Chart Tests

Control Chart Type	Test		Performance Status Indicated by Test Results	
	Number	Results	Improvement	Degradation
Annual Average Forced Outage(IMS) Frequency	1	value is above the UCL		X
		value is below the LCL when LCL>0	X	
	2	v1 or more consecutive values above the CL		X
		v2 or more consecutive values below the CL	X	
	3	2 out of 3 values above the UWL		X
		2 out of 3 values below the LWL	X	
	4	6 consecutive values increasing		X
		6 consecutive values decreasing	X	
Annual Average Accumulated Forced Outage(IMS) Duration	1	value is above the UCL		X
		value is below the LCL when LCL>0	X	
	2	v1 or more consecutive values above the CL		X
		v2 or more consecutive values below the CL	X	
	3	2 out of 3 values above the UWL		X
		2 out of 3 values below the LWL	X	
	4	6 consecutive values increasing		X
		6 consecutive values decreasing	X	
Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)	1	value is above the UCL	X	
		value is below the LCL when LCL>0		X
	2	v1 or more consecutive values above the CL	X	
		v2 or more consecutive values below the CL		X
	3	2 out of 3 values above the UWL	X	
		2 out of 3 values below the LWL		X
	4	6 consecutively increasing values	X	
		6 consecutively decreasing values		X

4.3. AVAILABILITY REPORTING

Each PTO shall submit an annual report to the ISO within 90 days after the end of each calendar year describing its Availability Measures performance. This annual report shall be based on Forced Outage(IMS) records. All Forced Outage(IMS) records shall be submitted by each PTO to the ISO and shall include the date, start time, end time, affected Transmission Facility, and the probable cause(s) if known.

5. MAINTENANCE PRACTICES

5.1. INTRODUCTION

These ISO Transmission Maintenance Standards, as they may be periodically revised in accordance with the provisions of the Transmission Control Agreement and this Appendix C, and as they may be clarified by the Maintenance Procedures, shall be followed by each PTO in preparing, submitting, and amending its Maintenance Practices. The Maintenance Practices will provide for consideration of the criteria referenced in Section 14.1 of the TCA, including facility importance.

5.2. PREPARATION OF MAINTENANCE PRACTICES

5.2.1. TRANSMISSION LINE CIRCUIT MAINTENANCE

As may be appropriate for the specific Transmission Line Circuits under the ISO's Operational Control, each PTO's Maintenance Practices shall describe the Maintenance activities for the various attributes listed below:

5.2.1.1. OVERHEAD TRANSMISSION LINES

- Patrols and inspections, scheduled and unscheduled
- Conductor and shield wire
- Disconnects/pole-top switches
- Structure grounds

- Guys/anchors
- Insulators
- Rights-of-way
- Structures/Foundations
- Vegetation Management

5.2.1.2. UNDERGROUND TRANSMISSION LINES

- Patrols and inspections, scheduled and unscheduled
- Cable/Cable systems
- Cathodic Protection
- Fluid pumping facilities
- Terminations
- Arrestors
- Rights-of-way
- Splices
- Structures/vaults/manholes
- Vegetation Management

5.2.2. STATION MAINTENANCE

As may be appropriate for the specific Stations under the ISO's Operational Control, each PTO's Maintenance Practices shall describe Maintenance activities for the various attributes listed below:

- Inspections, scheduled and unscheduled
- Battery systems
- Circuit breakers
- Direct Current transmission components
- Disconnect switches
- Perimeter fences and gates
- Station grounds
- Insulators/bushings/arrestors
- Reactive power components
- Protective relay systems
- Station Service equipment
- Structures/Foundations
- Transformers/regulators
- Vegetation Management

5.2.3. DESCRIPTIONS OF MAINTENANCE PRACTICES

Each PTO's Maintenance Practices shall include a schedule for any time-based Maintenance activities and a description of conditions that will initiate any performance-based activities. The Maintenance Practices shall describe the Maintenance methods for each substantial type of component and shall provide any checklists/report forms, which may be required for the activity. Where appropriate, the Maintenance Practices shall provide criteria to be used to assess the condition of a Transmission Facility. Where appropriate, the Maintenance Practices shall specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the Transmission Facility.

5.3. REVIEW AND ADOPTION OF MAINTENANCE PRACTICES

5.3.1. INITIAL ADOPTION OF MAINTENANCE PRACTICES

In conjunction with its application to become a PTO, each prospective PTO shall provide to the ISO its proposed Maintenance Practices which comply with the requirements set forth in this Appendix C and Section 14.1 of the Transmission Control Agreement. This information shall provide sufficient detail for the ISO to assess the proposed Maintenance Practices.

The ISO shall review the proposed Maintenance Practices and may provide recommendations for an amendment. To the extent there is any disagreement between the ISO and the prospective PTO regarding the prospective PTO's proposed Maintenance Practices, such disagreement shall be resolved by the ISO and prospective PTO so that the ISO and the prospective PTO will have adopted Maintenance Practices, consistent with the requirements of this Appendix C and the Transmission Control Agreement, for the prospective PTO at the time that the ISO assumes Operational Control of the prospective PTO's Transmission Facilities. To the extent there are no recommendations, the proposed Maintenance Practices will be adopted by the ISO and the prospective PTO as the Maintenance Practices for that prospective PTO.

5.3.2. AMENDMENTS TO THE MAINTENANCE PRACTICES

5.3.2.1. AMENDMENTS PROPOSED BY THE ISO

Each PTO shall have in place Maintenance Practices that have been adopted by the ISO as set forth in this Appendix C. The ISO shall periodically review each PTO's Maintenance Practices having regard to these ISO Transmission Maintenance Standards and Maintenance Procedures. Following such a review, the ISO may recommend an amendment to any PTO's Maintenance Practices by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The PTO may draft amended language in response to the ISO's recommendation. If the PTO exercises its option to draft amended language to the ISO's proposed amendment, the PTO shall so notify the ISO within 30 days after the receipt of notice from the ISO. The PTO will provide the ISO with its proposed amendment language in a time frame mutually agreed upon between the PTO and the ISO. If, after the ISO receives the proposed amendment language from the PTO, the ISO and the PTO are unable to agree on the language implementing the ISO recommendation, then the provisions of Section 5.3.3.2 of this Appendix C shall apply.

5.3.2.2. AMENDMENTS PROPOSED BY A PTO

Each PTO may provide to the ISO its own recommendation for an amendment to its own Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement.

5.3.3. DISPOSITION OF RECOMMENDATIONS

5.3.3.1. If the ISO makes a recommendation to amend the Maintenance Practices of a PTO, as contemplated in Section 5.3.2.1 of this Appendix C, that PTO shall have 30 Business Days to provide a notice to the ISO, pursuant to Section 26.1 of the Transmission Control Agreement, stating that it does not agree with the recommended amendment or that it intends to draft the language implementing the amendment, as set forth in Section 5.3.2.1 of this Appendix C. If the PTO does not provide such a notice, the amendment recommended by the ISO shall be deemed adopted.

If a PTO makes a recommendation to amend its own Maintenance Practices, as contemplated in Section 5.3.2.2 of this Appendix C, the ISO shall have 30 Business Days to provide a notice to that PTO, pursuant to Section 26.1 of the Transmission Control Agreement, that it does not concur with the recommended amendment. If the ISO does not provide such a notice, then the recommended amendment shall be deemed adopted. Notwithstanding the foregoing, if an amendment proposed by a PTO to its own Maintenance Practices meets the objectives of Section 2.1 of this Appendix C and is submitted in accordance with the requirements in Section 5.2 of this Appendix C, the ISO shall adopt said amendment.

If any amendment to a PTO's Maintenance Practices is adopted, the PTO will specify the transition time to implement the adopted amendment so as to ensure the ISO and PTO are clear as to the implementation time frame where Maintenance may be performed under both sets of practices.

5.3.3.2. If the ISO or a PTO makes a recommendation to amend Maintenance Practices and if the ISO or PTO provides notice within the 30 Business Days specified in Section 5.3.3.1 of this Appendix C that the ISO or PTO does not agree with the recommended amendment, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If, after such efforts, the PTO and the ISO cannot reach a resolution, the pre-existing Maintenance Practices shall remain in effect. Either Party may, however, seek further redress through appropriate processes, including non-binding discussions at the TMCC and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. The PTO may also request, during the initial attempts at resolution and at any stage of the redress processes, a deferral of the ISO recommended amendment and the ISO shall not unreasonably withhold its consent to such a request. Following the conclusion of any and all redress processes, the PTO's Maintenance Practices, as modified, if at all, by these processes, shall be deemed adopted by the ISO, as the Maintenance Practices for that PTO, pursuant to the implementation time frame agreed to between the PTO and the ISO.

5.3.3.3. If the ISO determines, that prompt action is required to avoid a substantial risk to reliability of the ISO Controlled Grid, it may direct a PTO to implement certain temporary Maintenance activities in a period of less than 30 Business Days, by issuing an advisory to the PTO to that effect, by way of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. Any advisory issued pursuant to this Section 5.3.3.3 shall specify why implementation solely under Sections 5.3.3.1 and 5.3.3.2 of this Appendix C is not sufficient to avoid a substantial risk to reliability of the ISO Controlled Grid, including, where a substantial risk is not imminent or clearly imminent, why prompt action is nevertheless required. The ISO shall consult with the relevant PTO before issuing a Maintenance advisory. Upon receiving such an advisory, a PTO shall implement the temporary Maintenance activities in question, as of the date specified by the ISO in its advisory, unless the PTO provides a notice to the ISO, in accordance with Section 26.1 of the Transmission Control Agreement, that the PTO is unable to implement the temporary Maintenance activities as specified. Even if the PTO provides such a notice, the PTO shall use its best efforts to implement the temporary Maintenance activities as fully as possible. All Maintenance advisories shall cease to have effect 90 Business Days after issuance by the ISO or on such earlier date as the ISO provides in its notice.

Any Maintenance advisories required to remain in effect beyond 90 Business Days shall require a recommendation process pursuant to Section 5.3.3.1 or Section 5.3.3.2 of this Appendix C.

5.4. QUALIFICATIONS OF PERSONNEL

All Maintenance of Transmission Facilities shall be performed by persons who, by reason of training, experience and instruction, are qualified to perform the task.

6. MAINTENANCE RECORD KEEPING AND REPORTING

A PTO shall maintain and provide to the ISO records of its Maintenance activities in accordance with this Section 6 of this Appendix C.

6.1. PTO MAINTENANCE RECORD KEEPING

The minimum record retention period for Transmission Facilities subject to time based scheduled intervals shall be the designated Maintenance cycle plus two years. The minimum record retention period for all other Transmission Facility Maintenance activities identified through inspection, assessment, diagnostic or another process shall be a minimum of 2 years after the date completed.

A PTO's Maintenance records shall, at a minimum, include the: 1) responsible person; 2) Maintenance date; 3) Transmission Facility; 4) findings (if any); 5) priority rating (if any); and 6) description of Maintenance activity performed.

6.2. PTO MAINTENANCE REPORTING

Each PTO will submit a Standardized Maintenance Report as outlined in the Maintenance Procedures. The ISO will accept, at the PTO's option, a Standardized Maintenance Report in either electronic or paper form.

If a PTO retains records in a manner that includes additional information, such records may be submitted in that manner.

Each PTO shall provide to the ISO Maintenance records as described in Section 6.1 and as set forth in the Maintenance Procedures.

6.3. ISO VISIT TO PTO'S TRANSMISSION FACILITIES

The ISO may visit Transmission Facilities in accordance with Section 18.3 of the Transmission Control Agreement to determine if the Maintenance Practices are being followed by a PTO.

7. ISO AND TRANSMISSION MAINTENANCE COORDINATION COMMITTEE

The ISO shall establish and convene a Transmission Maintenance Coordination Committee (TMCC). The TMCC shall develop and, if necessary, revise the Maintenance Procedures, including conveying information to and seeking input from PTOs and other interested stakeholders regarding these Maintenance Procedures and any proposed amendments or revision thereto. The TMCC will also make recommendations on the ISO Transmission Maintenance Standards and any proposed revisions or amendments thereto. The TMCC will convey information to and seek input from the PTOs and other interested stakeholders on these ISO Transmission Maintenance Standards and any proposed revisions or amendments thereto. The TMCC will also perform any other functions assigned in this Appendix C.

Although the role of the Transmission Maintenance Coordination Committee is advisory in nature, the ISO will strive to achieve a consensus among committee members.

8. REVISION OF ISO TRANSMISSION MAINTENANCE STANDARDS AND MAINTENANCE PROCEDURES

8.1 REVISIONS TO ISO TRANSMISSION MAINTENANCE STANDARDS

The ISO, PTOs, or any interested stakeholder may submit proposals to amend or revise these ISO Transmission Maintenance Standards. All proposals shall be initially submitted to the TMCC for review in accordance with this Appendix C. Any revisions to these ISO Transmission Maintenance Standards shall be made only upon recommendation by the TMCC and only in accordance with the provisions and requirements of the Transmission Control Agreement and this Appendix C.

8.2 REVISIONS TO AND DEVIATIONS FROM MAINTENANCE PROCEDURES

The ISO or any PTO may submit proposals to the TMCC to amend or revise the Maintenance Procedures. Any deviations from the Maintenance Procedures should be held to a minimum and will be negotiated between the ISO and the affected PTO.

9. INCENTIVES AND PENALTIES

9.1 DEVELOPMENT OF A FORMAL PROGRAM

The TMCC shall periodically investigate and report to the ISO on the appropriateness of a formal program of incentives and penalties associated with Availability Measures. Should the TMCC ever recommend that the ISO adopt a formal program of incentive and penalties, the formal program will only be adopted as set forth in Section 9.2 of this Appendix C.

9.2 ADOPTION OF A FORMAL PROGRAM

Any formal program of incentives and penalties adopted by the ISO in connection with matters covered in Section 14 of the Transmission Control Agreement or this Appendix C, shall be established only: 1) with respect to Availability Measures; 2) upon recommendation of the TMCC as set forth in Section 9.1 of this Appendix C; 3) by express incorporation into this Appendix C in accordance with the provisions of the Transmission Control Agreement; and 4) upon approval by the FERC. Nothing in this Appendix C shall be construed as waiving or limiting in any way the right of any party or PTO to oppose or protest any formal program of incentives and penalties filed, proposed or adopted by the ISO and/or FERC or any portion thereof.

9.3 IMPOSITION OF PENALTIES IN THE ABSENCE OF A FORMAL PROGRAM

In the absence of a formal program of incentives and penalties, the ISO may seek FERC permission for the imposition of specific penalties on a PTO on a case-by-case basis in the event that the relevant PTO 1) exhibits significant degradation trends in Availability performance due to Maintenance, or 2) is grossly or willfully negligent with regard to Maintenance.

9.4 NO WAIVER

Nothing in this Appendix C shall be construed as waiving the rights of any PTO to oppose or protest any incentive, penalty or sanction proposed by the ISO to the FERC, the approval by FERC of any specific penalty or sanction, or the specific imposition by the ISO of any FERC approved penalty or sanction on the PTO.

9.5 LIMITATIONS ON APPLICABILITY TO NEW PTOS

For a new PTO, the Availability Measures system needs to be used and updated during a five calendar year phase in period, as set forth in Section 4.2 of this

Appendix C, to be considered in connection with any formal program of incentives and penalties associated with Availability Measures.

10. COMPLIANCE WITH OTHER REGULATIONS/LAWS

Each PTO shall maintain and the ISO shall operate Transmission Facilities in accordance with Good Utility Practice, sound engineering judgment, the guidelines as outlined in the Transmission Control Agreement, and all other applicable laws and regulations.

10.1 SAFETY

Each PTO shall take proper care to ensure the safety of personnel and the public in performing Maintenance duties. The ISO shall operate Transmission Facilities in a manner compatible with the priority of safety. In the event there is conflict between safety and reliability, the jurisdictional agency regulations for safety shall take precedence.

11. DISPUTE RESOLUTION

Any dispute between the ISO and a PTO relating to matters covered in this Appendix C shall be subject to the provisions of the Transmission Control Agreement, including the dispute resolution provisions set forth therein.

EXHIBIT G

EXHIBIT G

General Order 95

Section III

Requirements for All Lines

35 Vegetation Management

Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances. The minimum clearances established in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions, shall be maintained. (Also see Appendix E for tree trimming guidelines).

When a utility has actual knowledge, obtained either through normal operating practices or notification to the utility, dead, rotten and diseased trees or portions thereof, that overhang or lean toward and may fall into a span, should be removed.

Communication and electric supply circuits, energized at 750 volts or less, including their service drops, should be kept clear of vegetation in new construction and when circuits are reconstructed or repaired, whenever practicable. When a utility has actual knowledge, obtained either through normal operating practices or notification to the utility, that any circuit energized at 750 volts or less shows strain or evidences abrasion from vegetation contact, the condition shall be corrected by reducing conductor tension rearranging or replacing the conductor, pruning the vegetation or placing mechanical protection on the conductor(s). For the purpose of this rule, abrasion is defined as damage to the insulation resulting from the friction between the tree and conductor. Scuffing or polishing of the insulating covering is not considered abrasion. Strain on a conductor is present when deflection causes additional tension beyond the allowable tension of the span. Contact between vegetation and conductors, in and of itself, does not constitute a violation of the rule.

Note: Revised January 13, 2006 by Decision No. 05-01-030 and August 20, 2009 by Decision No. 09-08-029.

EXCEPTIONS:

(1) Rule 35 requirements do not apply to conductors, or aerial cable that complies with Rule 57.4-C, energized at less than 60,000 volts, where trimming or removal is not practicableand the conductor is separated from the tree with suitable materials or devices to avoid conductor damage by abrasion and grounding of the circuit through the tree.

(2) Rule 35 requirements do not apply where the utility has made a "good faith" effort to obtain permission to trim or remove vegetation but permission was refused or unobtainable. A "good faith" effort shall consist of current documentation of a minimum of an attempted personal contact and a written communication, including documentation of mailing or delivery. However, this does not preclude other action or actions from demonstrating "good faith". If permission to trim or remove vegetation is unobtainable and requirements of exception 2 are met, the utility is not compelled to comply with the requirements of exception 1.

(3) The Commission recognizes that unusual circumstances beyond the control of the utility may result in nonconformance with the rules. In such cases, the utility may be directed by the Commission to take prompt remedial action to come into conformance, whether or not the nonconformance gives rise to penalties or is alleged to fall within permitted exceptions or phase–in requirements.

Note: Revised November 6,1992 by Resolution No. SU–15, September 20, 1996 by Decision No. 96–09–097 and January 23, 1997 by Decision No. 97–01–044.

(4) Mature trees whose trunks and major limbs are located more than six inches, but less than the clearance required by Table 1, Cases 13E and 14E, from primary distribution conductors are exempt from the minimum clearance requirement under this rule. The trunks and limbs to which this exemption applies shall only be those of sufficient strength and rigidity to prevent the trunk or limb from encroaching upon the six–inch minimum clearance under reasonably foreseeable local wind and weather conditions. The utility shall bear the risk of determining whether this exemption applies, and the Commission shall have final authority to determine whether the exemption applies in any specific instance, and to order that corrective action be taken in accordance with this rule, if it determines that the exemption does not apply.

Note: Added October 22, 1997 by Decision No. 97–10–056

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General Order 95

Section III

Requirements for All Lines

37 Minimum Clearances of Wires above Railroads, Thoroughfares, Buildings, Etc.

Clearance between overhead conductors, guys, messengers or trolley span wires and tops of rails, surfaces of thoroughfares or other generally accessible areas across, along or above which any of the former pass; also clearances between conductors, guys, structures, or other objects, shall not be less than those set forth in Table 1, at a Temperature of 60°F and no wind.

The clearance specified in Table 1, Case 1, Column A, B, D, E and F, shall in no case be reduced more than 5% below the tabular values because of temperature and loading as specified in Rule 43 or other conditions. The clearances specified in Table 1, Cases 2 to 6 inclusive, shall in no case be reduced more than 10% below the tabular values because of temperature and loading as specified in Rule 43 or other conditions.

The clearance specified in Table 1, Case 1, Column C (22.5 feet), shall in no case be reduced below tabular value because of temperature and loading as specified in Rule 43.

The clearances specified in Table 1, Cases 11, 12 and 13, shall in no case be reduced below the tabular values because of temperatures and loading as specified in Rule 43.

Where supply conductors are supported by suspension insulators at crossings over railroads which transport freight cars, the initial clearances shall be sufficient to prevent reduction to clearances less than 95% of the clearances specified in Table 1, Case through the breaking of a conductor in either of the adjoining spans.

Where conductors, dead ends, and metal pins are concerned in any clearance specified in these rules, all clearances of less than 5 inches shall be applicable from surface of conductors (not including tie wires), dead ends, and metal pins, except clearances between surface of crossarm and conductors supported on pins and insulators (referred to in Table 1, Case 9) in which case the minimum clearance specified shall apply between center line of conductor and surface of crossarm or other line structure on which the conductor is supported.

All clearances of 5 inches or more shall be applicable from the center lines of conductors concerned.

When measuring the minimum allowable vertical conductor clearances in a span, the minimum clearance applies to the specific location under the span being measured and not for the entire span.

Note: Modified January 8, 1980 by Decision No. 91186, March 9, 1988 by Resolution E-3076; and November 6, 1992 by Resolution SU-15, September 20, 1996 by Decision 96-09-097, January 23, 1997 by Decision 97-01-044 and January 13, 2006 by Decision No. 05-01-030

General Order 95

Section III

Requirements for All Lines

Table 1: Basic Minimum Allowable Vertical Clearance of Wires above Railroads, Thoroughfares, Ground or Water Surfaces; Also Clearances from Poles, Buildings, Structures or Other Objects (nn) (Letter References Denote Modifications of Minimum Clearances as Referred to in Notes Following This Table)

Case No.	Nature of Clearance	Wire or Conductor Concerned						
		A Span Wires (Other than TrolleySpan Wires) Overhead Guys and Messengers	B Communication Conductors (IncludingOpen Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts	C Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts	D Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8	E Supply Conductors and Supply Cables, 750 - 22,500 Volts	F Supply Conductors and Supply Cables, 22.5 - 300 kV	G Supply Conductors and Supply Cables, 300 - 550 kV(mm)
1	Crossing above tracks of railroads which transport or propose to transport freight cars (maximum height 15 feet, 6 inches) where not operated by overhead contact wires. (a) (b) (c) (d)	25 Feet	25 Feet	22.5 Feet	25 Feet	28 Feet	34 Feet	34 Feet (kk)
2	Crossing or paralleling above tracks of railroads operated by overhead trolleys. (b) (c) (d)	26 Feet (e)	26 Feet (e) (f) (g)	22.5 Feet (h) (i) (eee)	20 Feet (ii)	25 Feet (o) (ii)	30 Feet (o) (ii)	30Feet (o) (ii) (kk)
3	Crossing or along thoroughfares in urban districts or crossing thoroughfares in rural districts. (c) (d)	18 Feet (j) (k) (ii)	18 Feet (j) (l) (m) (ii) (aa)	19 Feet (hh) (eee)	20 Feet (ii)	25 Feet (o) (ii)	30 Feet (o) (ii)	30 Feet (o) (ii) (kk)
	Above ground along	15 Feet (k)	15 Feet (m) (n) (p)	19 Feet (eee)	19 Feet	25 Feet (o)	30 Feet (o) (p)	30 Feet (o) (kk)

4	thoroughfares in rural districts or across other areas capable of being traversed by vehicles or agricultural equipment.							
5	Above ground in areas accessible to pedestrians only	8 Feet	10 Feet (m) (q)	19 Feet (eee)	12 Feet	17 Feet	25 Feet (o)	25 Feet (o) (kk)
6	Vertical clearance above walkable surfaces on buildings, (except generating plants or substations) bridges or other structures which do not ordinarily support conductors, whether attached or unattached.	8 Feet (r)	8 Feet (r)	8 Feet	8 Feet	12 Feet	12 Feet	20 Feet (ll)
6a	Vertical clearance above non–walkable surfaces on buildings, (except generating plants or substations) bridges or other structures, which do not ordinarily support conductors, whether attached or unattached	2 Feet	8 Feet (yy)	8 Feet	8 Feet (zz)	8 Feet	8 Feet	20 Feet
	Horizontal clearance of conductor at rest from buildings (except generating plants and substations),	-	3 Feet (u)	3 Feet	3 Feet (u) (v)	6 Feet (v)	6 Feet (v)	15 Feet (v)

7	bridges or other structures (upon which men may work) where such conductor is not attached thereto (s) (t)							
8	Distance of conductor from center line of pole, whether attached or unattached (w) (x) (y)	-	15 inches (s) (aa)	15 inches (aa) (bb) (cc)	15 inches (o) (aa) (dd)	15 or 18 inches (o) (dd) (ee) (jj)	18 inches (dd) (ee)	Not Applicable
9	Distance of conductor from surface of pole, crossarm or other overhead line structure upon which it is supported, providing it complies with case 8 above (x) (ee)	-	3 inches (aa) (ff)	3 inches (aa) (cc) (gg)	3 inches (aa) (dd) (gg)	3 inches (dd) (gg) (jj)	1/4 Pin Spacing Shown in Table 2 Case 15 (dd)	1/2 Pin Spacing Shown in Table 2 Case 15 (dd)
10	Radial centerline clearance of conductor or cable (unattached) from non–climbable street lighting or traffic signal poles or standards, including mastarms, brackets and lighting fixtures, and from antennas that are not part of the overhead line system.	-	1 Foot (u) (rr) (ss)	15 inches (bb) (cc)	3 Feet (oo)	6 Feet (pp)	10 Feet (qq)	10 Feet (ll)
11	Water areas not suitable for sailboating (tt) (uu) (ww) (xx)	15 Feet	15 Feet	-	15 Feet	17 Feet	25 Feet	25 Feet (kk)
	Water areas suitable for sailboating, surface area	18 Feet	18 Feet	-	18 Feet	20 Feet	27 Feet	27 Feet (kk)

12	of: (tt) (vv) (ww) (xx) (A) Less than 20 acres (B) 20 to 200 acres (C) Over 200 to 2,000 acres (D) Over 2,000 acres	26 Feet 32 Feet 38 Feet	26 Feet 32 Feet 38 Feet	- - -	26 Feet 32 Feet 38 Feet	28 Feet 34 Feet 40 Feet	35 Feet 41 Feet 47 Feet	35 Feet (kk) 41 Feet (kk) 47 Feet (kk)
13	Radial clearance of bare line conductors from tree branches or foliage (aaa) (ddd)	-	-	18 inches (bbb)	-	18 inches (bbb)	1/4 pin spacing shown in Table 2, Case 15 (bbb) (ccc)	1/2 pin spacing shown in Table 2, Case 15
14	Radial clearance of bare line conductors from vegetation in Extreme and Very High Fire Threat Zones in Southern California (aaa) (ddd) (hhh) (jjj)	-	-	18 inches (bbb)	-	48 inches (bbb) (iii)	48 inches (fff)	120 inches (ggg)

References to Rules Modifying Minimum Clearances in Table 1

(a) Shall not be reduced more than 5% because of temperature or loading - Rule 37
  1. Supply lines - Rule 54.4–B1
  2. Communication lines - Rule 84.4–B1

(b) Shall be increased for supply conductors on suspension insulators, under certain conditions - Rule 37

(c) Special clearances are provided for traffic signal equipment - Rule 58.4–C

(d) Special clearances are provided for street lighting equipment - Rule 58.5–B

(e) Based on trolley pole throw of 26 feet. may be reduced where suitably protected - Rule 56.4–B2
  1. Supply guys - Rule 56.4–B2
  2. Supply cables and messengers - Rule 57.4–B2
  3. Communication guys - Rule 86.4–B2
  4. Communication cables and messengers - Rule 87.4–B2

(f) May be reduced depending on height of trolley contact conductors
  1. Supply service drops - Rule 54.8–C5
  2. Communication service drops - Rule 84.8–D5

(g) May be reduced and shall be increased depending on trolley throw
  1. Supply conductors (except service drops) - Rule 54.4–B2
  2. Communication conductors (except service drops) - Rule 84.4–B2

(h) May be decreased where freight cars are not transported.

1. Trolley contact and feeder conductors - Rule 74.4–B1
2. Trolley span wires - Rule 77.4–A

(i) May be reduced for trolley contact and span wires in subways, tunnels, under bridges and in fenced areas
1. Trolley contact conductors - Rule 74.4–E
2. Trolley span wires - Rule 77.4–B

(j) May be reduced at crossings over private thoroughfares and entrances to private property and over private property
1. Supply service drops - Rule 54.8–B2
2. Supply guys - Rule 56.4–A
3. Communication service drops - Rule 84.8–C2
4. Communication guys - Rule 86.4–A

(k) May be reduced along thoroughfares where not normally accessible to vehicles
1. Supply guys - Rule 56.4–A1
2. Communication guys - Rule 86.4–A1

(l) May be reduced where within 12 feet of curb line of public thoroughfares
1. Supply service drops - Rule 54.8–B1
2. Communication service drops - Rule 84.8–C1

(m) May be reduced for railway signal cables under special conditions - Rule 84.4–A4

(n) May be reduced in rural districts
1. Intentionally left blank
2. Intentionally left blank
3. Communication conductors along roads - Rule 84.4–A2

(o) May be reduced for transformer, regulator or capacitor leads
1. Transformer leads - Rule 58.1–B
2. Regulator or capacitor leads - Rule 58.1–B

(p) May be reduced across arid or mountainous areas
1. Supply conductors of more than 22,500 volts - Rule 54.4–A1
2. Communications conductors - Rule 84.4–A1

(q) Shall be increased or may be reduced under special conditions
1. Intentionally left blank
2. Intentionally left blank
3. Communications conductors - Rule 84.4–A3
4. Increased for communication service drops on industrial or commercial premises - Rule 84.8–C3a
5. Communication service drops on residential premises - Rule 84.8–C3b

(r) May be reduced above roofs of buildings under special conditions
1. Supply overhead guys - Rule 56.4–G
2. Supply service drops - Rule54.8–B4
3. Communication overhead guys - Rule 86.4–F
4. Communication conductors and cables- Rule 84.4–E
5. Communication service drops- Rule 84.8–C4

(s) Also applies at fire escapes, etc.
1. Supply conductors- Rule 54.4–H1
2. Vertical clearances- Rule 54.8B4a
3. Horizontal clearance- Rule 54.8–B4b
4. Communication conductors- Rule 84.4–E

(t) Special clearances where attached to buildings, bridges or other structures
1. Supply conductors of 750 - 22,500 volts- Rule 54.4–H2
2. Trolley contact conductors- Rule 74.4–E
3. Communication conductors- Rule 84.4–F

(u) Reduced clearances permitted under special conditions
1. Supply service drops on industrial or commercial premises- Rule 54.8–B4a
2. Supply cables, grounded - Rule 57.4–G
3. Communication cables beside buildings, etc.- Rule84.4–E
4. Communication conductors under bridges, etc.- Rule84.4–F
5. Communication service drops- Rule 84.8–C4
6. Communication cables passing nonclimbable street light poles, etc.- Rule 84.4–D4a

(v) May be reduced under special conditions
1. Supply conductors of 750 - 7,500 volts- Rule 54.4–H1
2. Supply transformer lead and bus wires, where guarded- Rule 58.1

(w) May be reduced at angles in lines and transposition points
1. Supply conductors- Rule 54.4–D1
2. Communication conductors- Rule 84.4–D5

(x) May be reduced for suitably protected lateral or vertical runs
1 Supply bond wires- Rule 53.4
.
2. Supply ground wires- Rule 54.6–B
3. Supply lateral conductors- Rule54.6–C
4. Supply vertical runs- Rule 54.6–D
5. Supply risers- Rule 54.6–E
6. Communication ground wires- Rule 84.6–B
7. Communication lateral conductors- Rule 84.6–C
8. Communication vertical runs- Rule84.6–D
9. Communication risers - Rule 84.6–E

(y) Increased clearances required for certain conductors
1. Unattached conductors on colinear and crossing lines- Rule 32.3
2. Unattached supply conductors- Rule 54.4–D3
3. Supply service drops on clearance crossarms - Rule 54.8–C2
4. Supply service drops on pole top extensions- Rule 54.8–C3
5. Unattached supply service drops - Rule 54.8–D
6. Communication lines, colinear, conflicting or crossing - Rule 84.4–D3
7. Communication conductors passing supply poles and unattached thereto- Rule 84.4–D4
8. Communication service drops on clearance crossarms - Rule84.8–D2
9. Communication service drops on pole top extensions - Rule84.8–D3
10. Unattached communication service drops- Rule 84.8–E

(z) Special provisions for police and fire alarm conductors require increased clearances- Rule 92.2

(aa) May be reduced under special provisions
1. Supply conductors of 0 - 750 volts in rack configuration - Rule 54.4–D5
2. Service supply drops from racks - Rule 54.8–F
3. Supply cables and messengers attached to poles - Rule 57.4–F
4. Communication conductors on communication poles - Rule 84.4–D
5. Communication conductors on crossarms - Rule 84.4–D1
6. Communication conductors attached to poles - Rule 84.4–D2
7. Communication service drops attached to poles - Rule 84.8–B
8. Communication cables and messengers - Rule 87.4–D

9. Supply or communication cables and messengers on jointly used poles - Rule 92.1–B
10. Communication open wire on jointly used poles - Rule 92.1–C
11. Multiconductor cable with bare neutral - Rule 54.10–B1
12. Communication conductors across or along public thoroughfares - Rule 84.4–A6

(bb) May be reduced for class t conductors of not more than 750 volts and of the same potential and polarity - Rule 74.4–D

(cc) Not applicable to trolley span wires - Rule 77.4–E

(dd) Special clearances for pole–top and deadend construction
1. Conductors deadended in vertical configuration on poles - Rule 54.4–C4
2. Conductors deadended in horizontal configuration - Rule 54.4–D8

(ee) Clearance requirements for certain voltage classifications - Rule 54.4–D2

(ff) Not applicable to communication conductors - Rule 84.4–D

(gg) Clearance from crossarms may be reduced for certain conductors
1. Suitable insulated leads to protect runs - Rule 54.4–E
2. Leads of 0 - 5,000 volts to equipment - Rule 54.4–E
3. Leads of 0 - 5,000 volts to cutouts or switches - Rule 58.3–A2

(hh) Reduced clearance permitted from temporary fixtures and lighting circuits 0 - 300 volts - Rule 78.3–A1

(ii) Special Clearances Required Above Public and Private Swimming Pools
1. Supply line conductors - Rule 54.4–A3
2. Supply service drops - Rule 54.8–B5
3. Communication line conductors - Rule 84.4–A5
4. Communication service drops - Rule 84.8–C5
5. Supply guys, span wires - Rule56.4–A3
6. Communication guys - Rule 86.4–A3

(jj) May be decreased in partial underground distribution 54.4–D2

(kk) Shall be increased by 0.025 feet per kV in excess of 300 kV

(ll) Shall be increased by 0.04 feet per KV in excess of 300 kV

(mm) Proposed clearances to be submitted to the cpuc prior to construction for circuits in excess of 550 kV.

(nn) Voltage shown in the table shall mean line–to–ground voltage for direct current (DC) systems

(oo) May Be reduced for grounded or multi–conductor cables
1. Grounded cables - Rule 57.4–H
2. Multi–Conductor cables - Rule 54.10–B2

(pp) May be reduced to 4 feet for voltages below 7,500 volts - Rule 54.4–D3

(qq) May be reduced to 6 feet for voltages below 75 kV

(rr) May be reduced for supply service drops - Rule 54.8–D1

(ss) May be reduced for communications service drops- Rule 84.8–E1

(tt) Where a federal agency or surrogate thereof has issued a crossing permit, clearances of that permit shall govern.

(uu) Or Where sailboating is prohibited and where other boating activities are allowed

(vv) Clearance above contiguous ground shall be 5 feet greater than in cases 11 or 12 for the type of water area served for boat launch facilities and for area contiguous thereto, that are posted, designated or specifically prepared for rigging of sailboats or other watercraft.

(ww) For controlled impoundments, the surface areas and corresponding clearances shall be based upon the high water level. for other waters, the surface areashall be that enclosed by its annual flood level. the clearance over rivers, streams and canals shall be based upon the largest surface areas of any one–mile long segment which includes the crossing. the clearance over a canal, river or stream normally used to provide access for sailboats to a larger body of water shall be the same as that required for the larger body of water

(xx) Water areas are lakes, ponds, reservoirs, tidal waters, rivers, streams and canals without surface obstructions

(yy) May be reduced over non–walkable structures - Rule 54.8 (Table 10)

(zz) May be reduced to 2 feet for conductors insulated in accordance with - Rule 20.9–G

(aaa) Special requirements for communication and supply circuits energized at 0 - 750 volts - Rule 35

(bbb) May be reduced for conductor of less than 60,000 volts when protected from abrasion and grounding by contact with tree - Rule 35

(ccc) For 22.5 kV to 105 kV, minimum clearance shall be 18 inches.

(ddd) Clearances in this case shall be maintained for normal annual weather variations, rather than at 60 degrees, no wind.

(eee) May be reduced to 18 feet if the voltage does not exceed 1000 volts and the clearance is not reduced to more than 5% below the reduced value of 18 feet because of temperature and loading as specified in Rules 37 and 43 .

(fff) Clearances in this case shall be increased for conductors operating above 88 kV, to the following:
1. Conductors operating between 88kV and a 110 kV shall maintain a 60 inch clearance
2. Conductors operating above 110 kV shall maintain a 120 inch clearance

(ggg) Shall be increased by 0.40 inch per kV in excess of 500 kV

(hhh) Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection's Fire and Resource Assessment Program (FRAP) Fire Threat Map. The FRAP Fire Threat Map is to be used to establish approximate boundaries for purposes of this rule. The boundaries of the map are to be broadly construed, and utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map. Southern California shall be defined as the following: Santa Barbara, Ventura, San Bernardino, Riverside, Los Angeles, Orange, and San Diego Counties.

(iii) May be reduced to 18 inches for conductors operating less than 2.4 kV.

(jjj) Clearances in this case shall not apply to orchards of fruit, nut or citrus trees that are plowed or cultivated. In those areas Case 13 clearances shall apply.

Note: Revised February 1, 1948 by Supplement No. 1 (Decision No. 41134, Case No. 4324) ; January 2, 1962 by Resolution E–1109 ; February 7, 1964 by Decision No. 66707 ; March 29, 1966 by Decision No. 70489; August 9, 1966 by Decision No. 71094; September 18, 1967 by Decision No. 72984; March 30, 1968 by Decision No. 73813; January 8, 1980 by Decision No. 91186; March 9, 1988 by Resolution E–3076; November 21, 1990 by Resolution SU–6; January 21, 1992 by Resolution SU–10; November 6, 1992 by Resolution SU–15, September 20, 1996 by Decision 96–09–097, October 9, 1996 by Resolution SU–40; January 23, 1997 by Decision 97–01–044 , January 13, 2006 by Decision No. 05-01-030 and August 20, 2009 by Decision No. 09-08-029.

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General Order 95

Appendix E

Clearance of Poles, Towers and Structures from Railroad Tracks

The following are guidelines to Rule 35 .

The radial clearances shown below are minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous to obtain greater clearances than those listed below:

Voltage of Lines	Case 13 of Table 1	Case 14 of Table 1
Radial clearances for any conductor of a line operating at 2,400 or more volts, but less than 72,000 volt	4 feet	6.5 feet
Radial clearances for any conductor of a line operating at 72,000 or more volts, but less than 110,000 volts	6 feet	10 feet
Radial clearances for any conductor of a line operating at 110,000 or more volts but less than 300,000 volts	10 feet	20 feet
Radial clearance for any conductor of a line operating at 300,000 or more volts	15 feet	20 feet

Note: Added November 6, 1992 by Resolution SU-15 and revised September 20, 1996 by Decision No. 96-09-097 and August 20, 2009 by Decision No. 09-08-029 .

EXHIBIT H

EXHIBIT H

LEO MORGAN, Complainant, vs. PACIFIC GAS AND ELECTRIC COMPANY, a corporation; DAVEY TREE SURGERY COMPANY, a corporation; MARSHALL PROSHOLD; RANDY COSTA; DOES 1 to 100, inclusive, Defendants

Decision No. 87-09-066, Case No. 86-07-051 (Filed July 28, 1986)

California Public Utilities Commission

1987 Cal. PUC LEXIS 239; 25 CPUC2d 393

September 23, 1987

Leo T. Morgan, for himself, complainant; Howard V. Golub and Lindsey How-Downing, Attorneys at Law, for Pacific Gas and Electric Company and Marshall Proshold; and Kevin O'Brien, Attorney at Law, for Davey Tree Surgery; defendants.

PANEL: [*1]

Stanley W. Hulett, President; Donald Vial, Frederick R. Duda, G. Mitchell Wilk, John B. Ohanian, Commissioners

OPINION: OPINION

This complaint alleges that Pacific Gas and Electric Company (PG&E) allows its tree-trimming contractor, Davey Tree Surgery (Davey), to "mutilate" trees in the Russian River area. Complainant is also concerned about the environmental consequences of Davey's application of herbicide around PG&E poles.

The complaint contends that the Commission has jurisdiction over Davey and the two individuals under Public Utilities (PU) Code § 216, which defines the term "public utility" as used elsewhere in the Code.

The complaint seeks the assessment of maximum penalties against the corporate defendants, and an order rescinding the PG&E/Davey contract. It also proposes new requirements for tree trimming and herbicide use and an order that PG&E use insulated lines wherever possible.

Defendant Proshold is the PG&E employee responsible for its tree-trimmingprogram [*2] in the area. Defendant Costa is a tree trimmer employed by Davey on PG&E work; he has been involved in arguments with complainant. Apparently, they were named as defendants primarily to secure their testimony. Nevertheless, the complaint seeks "disciplinary actions" against them and an order prohibiting defendant Costa from working on any utility-funded tree-trimming project.

Defendants PG&E and Davey both answered, denying any violation of the Public Utilities Code, General Order (GO) 95 or any other Commission order. Davey's answer was also filed on behalf of its employee, defendant Costa. PG&E moved to dismiss as to its employee; however, since the filing was in the form of a letter rather than a pleading, no ruling was issued.

Hearing was held in Guerneyville on March 5 before Administrative Law Judge (ALJ) Gilman. Complainant testified, supported by an individual who observed some trees during and after tree cutting. Both of the individual defendants testified, as did Davey's production and safety manager, and its field supervisor.

In its opening statement Davey contended that it and the two individuals are non-utilities; therefore it argued that the Commissionhas jurisdiction [*3] only over PG&E, and not over the other defendants. It did not make any motions based on this argument.

Complainant moved that the hearing be convened at locations outside of the hearing room for the purpose of examining trees. Because of the difficulty of making a record of all proceedings during a view, the ALJ denied the motion.

Discussion

Tree-Trimming

Complainant does not dispute that PG&E must have a tree-trimming program to clear foliage away from its lines. He does not dispute that an inadequate trimming program could increase wild-fires, and pose electrical hazards for energy company, telephone company, and cablevision employees as well as for members of the public. However, it is his belief that Davey cuts away too much foliage, producing clearances which are much greater than necessary for safety. He suggests that Davey crews, and Mr. Costa in particular, are motivated to do excessive cutting by a desire to annoy him.

In order to establish a cause of action within the Commission's jurisdiction, complainant relied on a CPUC staff guideline n1 which specifies a separation of 4 feet between limbs and lines carrying up to 72 kV. He argued that theguideline is a Commission [*4] order and that it establishes maximum distances. However, it appears on the document's face that it is merely a staff interpretation of the more general provisions of GO 95. It is also clear that the document specifies minimum, not maximum, separation distances.

n1 The guideline is set forth in a 1967 letter to all power line operators over the signature of the Commission's Secretary (the title of the office was subsequently changed to Executive Director). The separations given in the letter are described as ". . . only a guide for minimum clearances. . .".

There is no statute or regulation which sets maximum separations. GO 95 requires a tree-trimming program but specifies the objectives to be achieved, not specific clearances. (*Public Resources Code § 4293* authorizes the State Board of Forestry to establish minimum clearance requirements on mountain, forest, brush, and grass lands; the clearances specified are the same as set forth in the staff guideline.)

The testimony of the PG&E and Davey witnesses was, insofar as it supports Findings 1 through 7 below, uncontradicted. We could not find that the tree-trimming practices of Davey or of PG&Eare unreasonable or unlawful. [*5] We have found only one point where we cannot fully adopt the testimony.

PG&E's witness stated that the same radial clearances are required for power lines regardless of whether the line is bare wire or is primary tree wire. n2 The guideline, however, suggests that a utility may, in its discretion, reduce clearances around primary tree wire. (There is no parallel provision in Resources Code § 4293.)

n2 Primary tree wire has a thin non-conductive coating which is not intended to serve as full insulation. It will however reduce the fire and shock hazard should a tree limb come into contact with the wire.

Complainant took the position that PG&E should allow less than guideline clearances around primary tree wire and should install it in place of bare wires in many locations. However, he did not show that PG&E's decision not to reduce clearances around tree wire was unreasonable. Nor did he show that its decision not to install tree wire at any location was unreasonable.

Herbicide Use

The PG&E/Davey contract calls for herbicide to be used to suppress combustible growth under certain pole-mounted equipment (such as transformers) which could generate sparks and thus start ground [*6] fires. The testimony shows that Davey's herbicide use is intensively regulated by the California Department of Agriculture. This regulation applies to all of Davey's operations, not just to the fraction which is conducted for a utility. In addition, the chemicals used are subject to the jurisdiction of the Environmental Protection Agency. There is no apparent reason to add another layer of regulation on those herbicide uses which are provided for utilities. In any event, complainant has not shown that herbicide use violates statute or Commission order.

While no citation was provided, the PG&E witness claimed that the brush clearance was mandated by the California Department of Forestry. He also testified that the chemical used, Princpt 4, is less toxic than table salt.

Since no violation of the PU Code or Commission Order has been proven, the complaint should be denied.

Findings of Fact

1. It is a proper and customary procedure for tree surgeons to cut a limb back to the nearest lateral branch, on both utility and non-utility work. A tree surgeon will also remove dead or diseased limbs even when removal is not required to maintain minimum clearances.

2. When trimming [*7] around power lines, it is necessary to cut foliage back to more than the minimum clearance to allow for growth. In the Russian River area, most trimming for PG&E is on a two-year cycle, and must ensure that the separation will exceed minimums at the end of the cycle.

3. The separation around power lines must also allow for wind sway and line sag induced by hot weather.

4. When telephone messenger lines share power poles, the surgeon should cut away limbs which overhang such lines. If a limb were to fall on the messenger lines, it could interfere with electric service by pulling poles out of plumb.

5. Davey employees do not engage in excess cutting to obtain firewood for personal use. They are prohibited from taking wood cut from any company job.

6. Davey will try to obtain the consent of property owners for tree trimming under the PG&E contract. If owners ask for more trimming than necessary for utility purposes, Davey will often comply.

7. Caltrans, local government, and the telephone utility all trim roadside trees in the area of concern. Property owners sometimes contract for trimming for purposes other than power line clearance. It is not possibleunder this record [*8] to determine whether the trimming which complainant challenges was done under PG&E's contract with Davey.

8. Complainant has had heated discussions with witness Costa. These discussions have not motivated Costa to retaliate by cutting more wood than necessary.

Conclusions of Law

1. PG&E's tree-trimming program, as implemented under contract with Davey, is necessary to comply with GO 95. Excessive trimming if proven would not violate any Commission order.

2. There is no basis for an order to substitute tree wire for bare wire or to establish different clearances for trimming around tree wire.

3. PG&E's program to clear brush away from under poles does not violate any Commission order.

4. It is not necessary to rule on Davey's claim that we have no jurisdiction over it or either of the employees.

5. The complaint should be denied.

ORDER

IT IS ORDERED that the complaint is denied.

The order becomes effective 30 days from today.

Dated September 23, 1987 at San Francisco, California.

Legal Topics:

For related research and practice materials, see the following legal topics:
Communications LawU.S. Federal Communications CommissionJurisdictionEnergy & Utilities LawUtility CompaniesContracts for Service

EXHIBIT I

EXHIBIT I

Tower
Conductors
Conductors
Conductors
43 Ivy Dr, Orinda, CA 94563
© 2011 Google
Google
Imagery Date: Oct 2, 2009
lat 37.854288° lon -122.148485° elev 716 ft
Eye alt 1162 ft


43 Ivy Dr, Orinda, CA 94563
2 Birch Trees
© 2011 Google
lat 37.854261° lon -122.148215° elev 709 ft

EXHIBIT J

EXHIBIT J

64 M 16

TRACT 2420

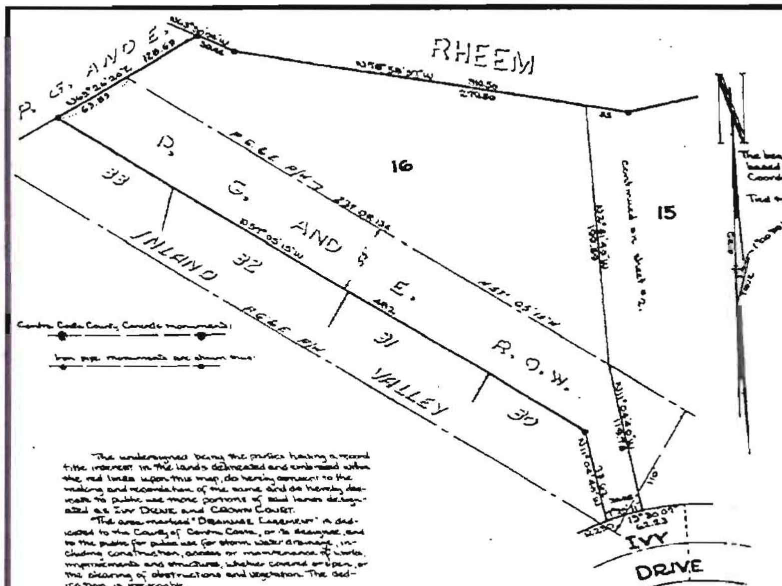
CONTRA COSTA COUNTY, CALIFORNIA

PORTION OF RANCHO LAGUNA DE LOS PALOS COLORADOS

WILSON & COMPANY — CIVIL & SUBDIVISION ENGINEERS

OAKLAND, CALIFORNIA — APRIL, 1956

SCALE: 1" = 50'



The bearings on this map are based on the California Coordinate System Zone III.

Tied to grid with bearings from Inland Valley Subdivision

I, Victor W. Sauer Road Commissioner-Surveyor of the County of Contra Costa, State of California do hereby certify that I have examined the map of "Tract 2420 Contra Costa County, California," etc., and that said subdivision is substantially as it appeared on the tentative map, and that all the provisions of State Laws and Local Ordinances, governing the filing of subdivision maps have been complied with and I am satisfied that said map is technically correct.

V. W. Sauer
Road Commissioner-Surveyor of Contra Costa County, State of California

By F. R. Brown
Deputy Road Commissioner

Dated: May 22, 1956

The map entitled "Tract 2420, Contra Costa County, California," etc., is hereby accepted for recordation showing a clear title as per letter of title made by the Contra Costa County Title Company dated the 25th day of May in the year Nineteen hundred and Fifty-six and after examining the same, I deem that said map complies in all respects with the provisions of State Laws and Local Ordinances governing the filing of subdivision maps.

Ralph Cunningham
County Recorder in and for the County of Contra Costa, State of California

By [signature]
Deputy County Recorder

The undersigned being the parties having a record title interest in the lands delineated and embraced within the red lines upon this map, do hereby consent to the making and recordation of the same and do hereby dedicate to public use those portions of said lands designated as Ivy Drive and Crown Court.

The area marked "Drainage Easement" is dedicated to the County of Contra Costa, or its assignee, and to the public for public use for storm water drainage, including construction, access or maintenance of works, improvements and structures, whether covered or open, or the clearing of obstructions and vegetation. The dedication is irrevocable.

Utah Construction Company

F. M. Keller
Vice President

J. M. Harrigan
Asst. Secretary

State of California }ss
County of Contra Costa }

On the 17th day of May in the year Nineteen Hundred and Fifty-six before me William A. Holton, a Notary Public, in and for said County and State, residing therein, duly commissioned and sworn, personally appeared F. M. Keller known to me to be the Vice President, and J. M. Harrigan known to me to be the Asst. Secretary of the corporation that executed the foregoing statements and also known to me to be the persons who executed it on behalf of said corporation and acknowledged to me that said corporation executed the same.

Witness my hand and official seal

William A. Holton
Notary Public in and for the County of Contra Costa, State of California

My Commission expires Oct. 4 1959

State of California }ss
County of Contra Costa }

I, W. T. Paasch, County Clerk and Ex-officio Clerk of the Board of Supervisors of the County of Contra Costa, State of California, do hereby certify that the above and foregoing map entitled "Tract 2420 Contra Costa County, California," etc., was presented to said Board of Supervisors, as provided by law, at a regular meeting thereof, held on the 22nd day of May 1956, and that said Board of Supervisors did thereupon by resolution duly passed and adopted at said meeting, approve said map and did not accept on behalf of the public any of the streets or easements as dedicated to public use.

I further certify that all the bonds as required by law to accompany the aforesaid map have been approved by the Board of Supervisors of Contra Costa County and filed in my office.

In Witness Whereof, I have hereunto set my hand this 22nd day of May 1956.

W. T. Paasch
County Clerk and Ex-officio Clerk of the Board of Supervisors, County of Contra Costa, State of California.

By [signature]
Deputy County Clerk

"Tract 2420, Contra Costa County, California," etc., is a portion of Rancho Laguna De Los Palos Colorados, Contra Costa County, California.

Containing 13.3 Acres more or less.

No part of this subdivision lies within the incorporated area of any city or town.

I hereby certify that the subdivision shown on this map was made from a true and complete survey made under my direction in April 1956; that the monuments will be of the character and occupy the positions indicated and will be set in such positions in accordance with the satisfactory assurance given by the subdivider that said monuments will be sufficient to enable the survey to be retraced.

The bearings on this map are based on the California Coordinate System Zone III.

Dated: April 13, 1956

F. W. Dracopoli
Licensed Land Surveyor No. 2300

Seal

Recorded at the request of the Contra Costa County Title Company at 25 minutes past 1 P.M. on the 26th day of May 1956 in the office of the County Recorder of the County of Contra Costa, State of California.

Ralph Cunningham
County Recorder in and for the County of Contra Costa, State of California

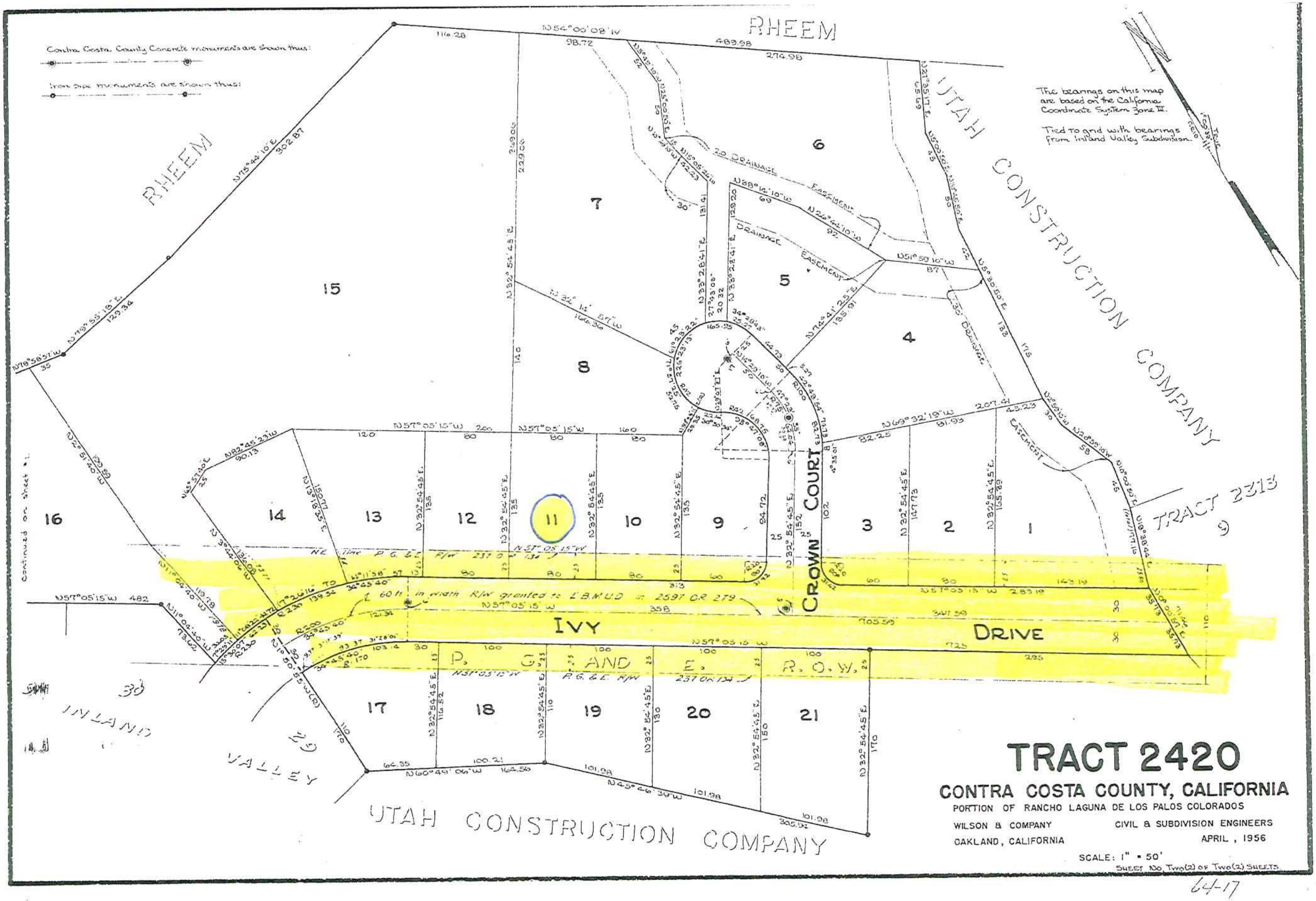
By [signature]
Deputy County Recorder

I certify that the Planning Commission of Contra Costa County, State of California, has approved the tentative map of the subdivision upon which this final map is based.

Director of Planning

By H. Russell Griffith
Principal Planner 5-17-56

Dated: ____________ 1956.



Contra Costa County Concrete monuments are shown thus:
Iron pipe monuments are shown thus:
The bearings on this map are based on the California Coordinate System Zone III.
Tied to grid with bearings from Inland Valley Subdivision.
RHEEM
RHEEM
UTAH CONSTRUCTION COMPANY
UTAH CONSTRUCTION COMPANY
INLAND VALLEY
TRACT 2313
Continued on sheet #1
IVY DRIVE
CROWN COURT
P. G. AND E. R. O. W.
60 ft in width R/W granted to E.B.M.U.D. in 2597 OR 279
NE line P.G.&E. R/W 2370 R 134
P.G.&E. R/W 2370R 134
DRAINAGE EASEMENT
20' DRAINAGE EASEMENT
EASEMENT
TRACT 2420
CONTRA COSTA COUNTY, CALIFORNIA
PORTION OF RANCHO LAGUNA DE LOS PALOS COLORADOS
WILSON & COMPANY
OAKLAND, CALIFORNIA
CIVIL & SUBDIVISION ENGINEERS
APRIL, 1956
SCALE: 1" = 50'
SHEET No. Two(2) of Two(2) SHEETS
64-17