Regulatory Analysis Form

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INDEPENDENT REGULATORY REVIEW COMMISSION

IRRC Number: 2571

(1) Agency

Pennsylvania Public Utility Commission

(2) I.D. Number (Governor*s Office Use)

L-00040167/57-248

(3) Short Title

Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection, Maintenance, Repair, and Replacement Standards for Electric Distribution Companies.

(4) PA Code Cite

52 Pa. Code Sections 57.192 and 57.198

(5) Agency Contacts & Telephone Numbers

Primary Contact: Elizabeth H. Barnes, Law Bureau (717)772-5408

Secondary Contact: Blaine Loper, CEEP (717)787-3810

(6) Type of Rulemaking (check one)

☐ Proposed Rulemaking
☒ Final Order Adopting Regulation
☐ Final Order, Proposed Rulemaking Omitted

(7) Is a 120-Day Emergency Certification Attached?

☒ No
☐ Yes: By the Attorney General
☐ Yes: By the Governor

(8) Briefly explain the regulation in clear and nontechnical language.

The rulemaking order adds a regulation at 52 Pa.Code §57.198, requiring electric distribution companies to biennially file 2-year plans for inspection, maintenance, repair and replacement of their facilities. The regulation further establishes minimum standards regarding vegetation management, pole inspections, overhead line and transformer inspections, reclosers and substation inspections. Specifically, the rulemaking seeks to implement actions recommended in the Legislative Budget and Finance Committee report of June 12, 2002, as well as Section 2802(20) of the Public Utility Code, 66 Pa. C.S. 2802(20).

(9) State the statutory authority for the regulation and any relevant state or federal court decisions.

The authority for the regulation is the Electricity Generation Customer Choice and Competition Act of December 3, 1996, P.L. 138 §4, effective January 1, 1997. The Act amends Title 66 of the Pennsylvania Consolidated Statutes by adding Chapter 28 to establish standards and procedures to create direct access by retail customers to the competitive market for the generation of electricity, while maintaining the safety and reliability of the electric system. Specifically, the Commission was given a legislative mandate to ensure that levels of reliability that were present prior to the restructuring of the electric industry would continue in the new competitive era. 66 Pa.C.S. §2802(20) states that the Commission shall set through regulations, inspection, maintenance, repair and replacement standards and enforce those standards.

In response to this legislative mandate, the Commission adopted a final rulemaking order on May 22, 2008 at

Docket No. L-00040167, setting forth various reporting requirements designed to ensure the continuing safety, adequacy and reliability of the distribution of electricity in the Commonwealth. 52 Pa.Code §§57.198.

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(10) Is the regulation mandated by any federal or state law or court order, or federal regulation? If yes, cite the specific law, case or regulation, and any deadlines for action.

Yes. 66 Pa.C.S. §2802(12) provides that the purpose of the restructuring of the electric utility industry is to modify existing legislation and regulations and to establish standards and procedures in order to create direct access by retail customers to the competitive market for the generation of electricity while maintaining the safety and reliability of the electric system for all parties. Thus, the Commission was given a legislative mandate that electric reliability levels stay the same during the transition period from a non-competitive environment to a competitive one.

Additionally, 66 Pa. C.S. §2802(20) provides that the Commission shall set through regulations, inspection, maintenance, repair and replacement standards and enforce those standards.

(11) Explain the compelling public interest that justifies the regulation. What is the problem it addresses?

In order to ensure a smooth transition from a monopoly market to a competitive market, there should be inspection and maintenance standards based upon commonly accepted principles in the industry, national standards and state standards in order to ensure that service does not deteriorate. The companies until this time, have only been beholden to their own individual standards.

(12) State the public health, safety, environmental or general welfare risks associated with nonregulation.

Without these regulations, the service quality of electric distribution could deteriorate.

(13) Describe who will benefit from the regulation. (Quantify the benefits as completely as possible and approximate the number of people who will benefit.)

All consumers will benefit, both customers of the 6 large EDCs and the 4 small. Residential and business, rural and urban customers alike would benefit from these regulations.

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(14) Describe who will be adversely affected by the regulation. (Quantify the adverse effects as completely as possible and approximate the number of people who will be adversely affected.)

No person or entity will be adversely affected by the regulations. The Commission took into consideration the electric distribution companies' past internal inspection and maintenance standards along with their reliability indices in determining fair and reasonable inspection and maintenance standards. The benefit to consumers of having minimum inspection and maintenance standards outweighs any additional incremental cost to the industry.

(15) List the persons, groups or entities that will be required to comply with the regulation. (Approximate the number of people who will be required to comply.)

All of the Electric Distribution Companies will be required to comply with the regulations. The list of EDCs includes Allegheny Power, Duquesne Light, Met-Ed, Penelec, Penn Power, PECO, PPL, Citizens, Wellsboro, UGI and Pike County.

(16) Describe the communications with and input from the public in the development and drafting of the regulation. List the persons and/or groups who were involved, if applicable.

The Commission Staff spoke with representatives from the large EDCs and small EDCs before recommending changes to the regulations to the Commission. Commission Staff also held a technical conference on January 22, 2007, at which time it listened to presentations by OCA, AFL-CIO - Utility Caucus, Pennsylvania Utility Contractors Association, IECPA, and most of the EDCs. Senator Tomlinson and IRRC also provided written comments to the Commission.

(17) Provide a specific estimate of the costs and/or savings to the regulated community associated with compliance, including any legal, accounting or consulting procedures which may be required.

Compliance should bring about savings to the regulated community that they would have otherwise lost due to interrupted electric service. The Commission does not anticipate any additional costs to consumers as a result of compliance with the proposed regulation.

(18) Provide a specific estimate of the costs and/or savings to local governments associated with compliance, including any legal, accounting or consulting procedures which may be required.

Not applicable

(19) Provide a specific estimate of the costs and/or savings to state government associated with the implementation of the regulation, including any legal, accounting, or consulting procedures which may be required.

Any costs would be de minimus.

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(20) In the table below, provide an estimate of the fiscal savings and costs associated with implementation and compliance for the regulated community, local government, and state government for the current year and five subsequent years.

	Current FY Year	FY +1 Year	FY +2 Year	FY +3 Year	FY +4 Year	FY +5 Year
SAVINGS:	$	$	$	$	$	$
Regulated Community						
Local Government						
State Government						
Total Savings						
COSTS:						
Regulated Community						
Local Government						
State Government						
Total Costs						
REVENUE LOSSES:						
Regulated Community						
Local Government						
State Government						
Total Revenue Losses						

(20a) Explain how the cost estimates listed above were derived.

Not applicable.

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(20b) Provide the past three year expenditure history for programs affected by the regulation.

Program	FY -3	FY -2	FY -1	Current FY

(21) Using the cost-benefit information provided above, explain how the benefits of the regulation outweigh the adverse effects and costs.

Not applicable.

(22) Describe the nonregulatory alternatives considered and the costs associated with those alternatives. Provide the reasons for their dismissal.

None.

(23) Describe alternative regulatory schemes considered and the costs associated with those schemes. Provide the reasons for their dismissal.

None.

(24) Are there any provisions that are more stringent than federal standards? If yes, identify the specific provisions and the compelling Pennsylvania interest that demands stronger regulation.

None.

(25) How does this regulation compare with those of other states? Will the regulation put Pennsylvania at a competitive disadvantage with other states?

Massachusettes has Service Quality Standards. New Jersey and New York also have reliability standards and regulations. Missouri, California and Ohio also have inpsection and maintenance reliability standards. It is believed that the regulation will not put Pennsylvania at a competitive disadvantage with other states. More reliable electric service attracts businesses to our State, thus providing more jobs for our residents.

(26) Will the regulation affect existing or proposed regulations of the promulgating agency or other state agencies? If yes, explain and provide specific citations.

No.

(27) Will any public hearings or informational meetings be scheduled? Please provide the dates, times, and locations, if available.

Not at this time.

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(28) Will the regulation change existing reporting, record keeping, or other paperwork requirements? Describe the changes and attach copies of forms or reports which will be required as a result of implementation, if available.

The Commission or its Staff will have to annually prepare Secretarial Letters approving or rejecting the EDCs' plans.

(29) Please list any special provisions which have been developed to meet the particular needs of affected groups or persons including, but not limited to, minorities, elderly, small businesses, and farmers.

None.

(30) What is the anticipated effective date of the regulation; the date by which compliance with the regulation will be required; and the date by which any required permits, licenses or other approvals must be obtained?

We are asking for compliance in filing biennial plans beginning October 1, 2009.

(31) Provide the schedule for continual review of the regulation.

An annual report will be issued by the Commission critiquing the regulation, standards and performance in the EDC industry.

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FACE SHEET
FOR FILING DOCUMENTS
WITH THE LEGISLATIVE REFERENCE BUREAU

(Pursuant to Commonwealth Documents Law)

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INDEPENDENT REGULATORY
REVIEW COMMISSION

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Copy below is hereby approved as to form and legality. Attorney General.	Copy below is hereby certified to be true and correct copy of a document issued, prescribed or promulgated by:	Copy below is hereby approved as to form and legality. Executive or independent Agencies.
BY ________ (DEPUTY ATTORNEY GENERAL)	Pennsylvania Public Utility Commission (AGENCY)	BY Bohdan R. Pankiw, Chief Counsel
________ DATE OF APPROVAL	DOCUMENT/FISCAL NOTE NO. L-00040167/57-248 DATE OF ADOPTION May 22, 2008	5-22-08 DATE OF APPROVAL
☐ Check if applicable Copy not approved. Objections attached	BY James J. McNulty TITLE (SECRETARY)	☐ Check if applicable. No Attorney General approval or objection within 30 days after submission.

L-00040167/57-248
Final Rulemaking
Pertaining to Adding Inspection and Maintenance
Standards for EDCs
52 Pa. Code, Chapter 57

The Pennsylvania Public Utility Commission on May 22, 2008, adopted a final rulemaking order which implements minimum inspection, maintenance, repair and replacement standards on electronic distribution companies operating in Pennsylvania. The contact persons are Blaine Loper, CEEP, 787-3810 and Elizabeth Barnes, Law Bureau, 772-5408.

EXECUTIVE SUMMARY

L-00040167/57-248
Final Rulemaking
Adding Inspection and Maintenance
Standards for EDCs
52 Pa.Code, Chapter 57

The Electricity Generation Customer Choice and Competition Act (Act), 1996, Dec. 3, P.L. 802, No. 138 §4, became effective January 1, 1997. The Act amends Title 66 of the Pennsylvania Consolidated Statutes ("Public Utility Code" or "Code") by adding Chapter 28 to establish standards and procedures to create direct access by retail customers to the competitive market for the generation of electricity, while maintaining the safety and reliability of the electric system. Specifically, 66 Pa. C.S. §2802(20) provides:

> (20) Since continuing and ensuring the reliability of electric service depends on adequate generation and on conscientious inspection and maintenance of transmission and distribution systems, the independent system operator or its functional equivalent should set, and the commission shall set through regulations, inspection, maintenance, repair and replacement standards and enforce those standards.

In our Final Rulemaking Order entered May 20, 2004, at L-00030161 *Rulemaking Re Amending Electric Service Reliability Regulations at 52 Pa. Code Chapter 57,* Final Rulemaking Order, the Commission declined at that time to require specific inspection and maintenance standards reasoning that technological advances continue to improve the inspection and testing process. The Commission asked companies to report their own internal inspection and maintenance standards. The Commission measured the EDCs' progress towards meeting their individual goals and considered this information along with whether the EDCs were meeting their reliability standards to determine whether service was deteriorating or not within a given service territory due to the fault of the EDC.

After the blackout of August 2003, new information arose which caused this Commission to reevaluate the need for specific inspection and maintenance standards. One of the causes of the blackout was the failure of FirstEnergy Corporation to adequately manage tree growth along transmission lines. *Final Report on the August 14 Blackout in the U.S. and Canada*, U.S. –Canada Power System Outage Task Force, pp. 17, 57-64 (April 2004).

This Final Rulemaking Order seeks to implement minimum inspection, maintenance, repair and replacement standards on electric distribution companies operating in Pennsylvania. The Commission proposes to require an initial inspection and maintenance plan for upcoming calendar years due by October 1, 2009 for Compliance Group 1 and October 1, 2010 for Compliance Group 2 which shall cover the two calendar years beginning 15 months following October 1. The plan shall cover two years, and shall be filed biennially. The plan shall detail a program for the maintenance of electric distribution facilities including: poles, wires, conduits or other fixtures, along public highways or streets for the distribution of electric current, owned, operated, managed or controlled by such company in such format as Commission staff shall prescribe. These plans are subject to acceptance or rejection by the Commission or its Bureau of Conservation, Economics and Energy Planning if the minimum inspection and maintenance intervals as outlined in Annex A, proposed regulation Section 57.198(n) are not included in the plans without justification. Annex A contains minimum standards for vegetation management, pole inspections, distribution overhead line and transformer inspections, recloser inspections, and substation inspections.

The contact persons are Elizabeth Barnes, Law Bureau (717)772-5408, and Blaine Loper, Bureau of Conservation, Economics and Energy Planning (717)787-3810.

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, Pennsylvania 17105-3265

Public Meeting held May 22, 2008

Commissioners Present:

Wendell F. Holland, Chairman
James H. Cawley, Vice Chairman
Tyrone J. Christy
Kim Pizzingrilli, Statement attached

Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection, Maintenance, Repair, and Replacement Standards for Electric Distribution Companies

Docket No. L-00040167

FINAL RULEMAKING ORDER

BY THE COMMISSION:

In this final rulemaking order, the Commission is adopting final-form regulations designed to improve the monitoring and achievement of reliability performance in the electric distribution industry by establishing inspection, maintenance, repair and replacement standards ("I&M standards") and creating a new regulation at 52 Pa. Code §57.198, requiring biennial filings regarding companies' inspection, maintenance, repair and replacement plans ("I&M plans") that fit within the standards' intervals.

Since the Electricity Generation Customer Choice and Competition Act (Act), 1996, Dec. 3, P.L. 802, No. 138 §4, became effective January 1, 1997, we have been examining the EDCs' inspection, maintenance, repair and replacement internal standards and have been evaluating what kind of standards to implement through regulations in order to comply with the legislative mandate to ensure that levels of reliability that were present prior to the restructuring of the electric utility industry would continue in the new competitive markets. 66 Pa.C.S. §§2802(12), 2802(20), 2804(1) and 2807(d).

By this regulation, beginning October 1, 2009, the EDCs shall be required to biennially file, on or before October 1st every other year, I&M plans explaining their plans for inspection, maintenance, replacement and repair for the upcoming calendar year. The regulation also establishes I&M standards for a variety of activities such as vegetation management, pole inspections, overhead line inspections and substation inspections, based on current industry practices and the comments submitted in this rulemaking proceeding.

However, the regulation will allow the individual EDCs to deviate from the standards set forth in the regulation, provided that such deviation can be justified based on utility-specific circumstances or a cost/benefit analysis. In this fashion, where compliance with a given I&M standard for a specific EDC would not be prudent or cost/benefit justified, the EDC may deviate from that standard provided that it can adequately justify the different I&M interval or approach.

The Commission, therefore, finds that this final-form regulation will comply with the requirements of Chapter 28 and our fundamental obligations to ratepayers of Pennsylvania to maintain adequate service reliability without imposing unjustified costs.

I. Procedural History

The Act amends Title 66 of the Pennsylvania Consolidated Statutes ("Public Utility Code" or "Code") by adding Chapter 28 to establish standards and procedures to permit direct access by retail customers to the competitive market for the generation of electricity, while maintaining the safety and reliability of the electric system. Specifically, the Commission was given a legislative mandate to ensure that levels of reliability that were present prior to the restructuring of the electric utility industry would continue in the new competitive markets. 66 Pa.C.S. §§2802(12), 2804(1) and 2807(d).

In response to this legislative mandate, the Commission adopted a final rulemaking order on April 23, 1998 at Docket No. L-00970120, setting forth various reporting requirements designed to ensure the continuing safety, adequacy and reliability of the generation, transmission and distribution of electricity in the Commonwealth. *See* 52 Pa. Code §§57.191-57.197. These reporting requirements included, *inter alia*, descriptions of each major event affecting reliability, the achieved values on various reliability indices (SAIFI, CAIDI, SAIDI and MAIFI), analysis of major outages during the study, and a list of remedial efforts taken for the EDC's worst performing 5% of circuits. However, while the EDCs were obligated to report on their inspection and maintenance goals and actual results, the regulation contained no standards by which those practices would be measured. The final rulemaking order also suggested that the Commission could reevaluate its monitoring efforts at a later time as deemed appropriate.

On June 12, 2002, the Legislative Budget and Finance Committee (LB&FC) issued a Report entitled, *Assessing the Reliability of Pennsylvania's Electric Transmission and Distribution Systems*. The LB&FC Report made several recommendations regarding the issue of reliability including: revising and enhancing

EDC reliability reporting requirements and performance monitoring standards, clarifying reporting requirements regarding the exclusion of data for major events, requiring formal waivers for EDCs unable to comply with all reporting requirements, and completing the pending inspection and maintenance study by our staff.

Shortly thereafter, on July 18, 2002, at M-00021619, the Commission adopted its Bureau of Conservation Economics and Energy Planning's (CEEP) *Inspection and Maintenance Study of Electric Distribution Systems* dated July 3, 2002. CEEP, in part, recommended that the annual reliability reporting requirements be revised to include the causes of outages and percentages categorized by type as well as the annual reporting of each company's planned inspection and maintenance activities including: (1) vegetation management; (2) distribution and substation maintenance activity; and (3) capital improvement projects. The Commission agreed with CEEP's recommendations in this regard.

The Commission created a Staff Internal Working Group on Electric Service Reliability (Staff Internal Working Group) to conduct a reevaluation of its electric service reliability efforts. The group was comprised of members of Commission bureaus with either direct or indirect responsibility for monitoring electric service reliability.

The Staff Internal Working Group prepared a report, entitled *Review of the Commission's Monitoring Process For Electric Distribution Service Reliability*, dated July 18, 2002, which reviewed the Commission's monitoring process for electric distribution service reliability and provided comments on recommendations from the LB&FC report. The Staff Internal Working Group report also offered recommendations for tightening the standards for reliability performance and establishing additional reporting requirements by electric distribution companies (EDCs).

On August 29, 2002, the Commission issued an order at Docket No. D-02SPS021 that tentatively approved these recommendations and directed the Commission staff to undertake the preparation of orders, policy statements, and proposed rulemakings as may be necessary to implement the recommendations contained in the Staff Internal Working Group's report. The Staff Internal Working Group was assigned the responsibility to implement the recommendations. The Staff Internal Working Group determined which implementation actions could be accomplished internally (with or without a formal Commission order), and which actions will require changes to regulations.

On June 27, 2003, at Docket No. L-00030161, the Commission adopted proposed regulations governing the reliability of electric service in Pennsylvania. On May 7, 2004 a final rulemaking order was entered at Docket No. L-00030161 *Rulemaking Re Amending Electric Service Reliability Regulations at 52 Pa. Code Chapter 57.* While the Commission did increase its reporting requirements of the EDCs, the Commission declined at that time to require specific inspection, maintenance and repair standards reasoning that technological advances continue to improve the inspection and testing process. The Commission asked companies to progress towards meeting their individual goals and considered this information along with whether the EDCs were meeting their reliability standards to determine whether service was deteriorating or not within a given service territory due to the fault of the EDC.

However, after the blackout of August 14, 2003, new information arose which caused this Commission to reevaluate the need for specific inspection and maintenance standards to supplement its existing measures to ensure reliability. In particular, the Commission observed that one of the fundamental causes of the blackout was the failure of FirstEnergy Corporation to adequately manage tree growth along transmission lines. *Final Report on the August 14 Blackout in the U.S. and Canada, Canada Power System Outage Task Force*, pp. 17, 57-64 (April 2004). The Commission also took note of the language in Section 2802(20) of the Public Utility Code which appears to mandate, through regulations, the establishment of "inspection, maintenance, repair, and replacement standards" to ensure the reliability of electric service in Pennsylvania. 66 Pa. C.S. § 2802(20).

On April 20, 2006, the Commission adopted a proposed rulemaking order seeking to implement proposed minimum inspection, maintenance, repair and replacement ("I&M") standards on EDCs. The comment deadline was extended in order to hold a technical conference at the Commission on January 22, 2007. Presentations were offered by two panels at the technical conference. The first panel consisted of the Office of Consumer Advocate and AFL-CIO – Utilities Caucus that generally supported the proposed regulations. The second panel consisted of UGI Utilities, Duquesne Light company, Allegheny Power, PPL Electric Utilities Corporation, PECO Energy Company and FirstEnergy. The second panel generally agreed with a requirement to submit I&M plans, but disputed the proposed regulations regarding setting minimum I&M standards.

At the technical conference Commission staff asked questions of the presenters, and supplemental responses to some data requests and other comments were timely submitted by April 16, 2007, by many interested parties including: the Attorney General's Office of Consumer Advocate (OCA), AFL-CIO Utility Caucus (AFL-CIO), Pennsylvania Utility Contractors Association (PUCA), Office of Small Business Advocate (OSBA), Citizens' Electric Company (Citizens'), Wellsboro

Electric Company (Wellsboro), Metropolitan Edison Company (Met-Ed), Pennsylvania Electric Company (Penelec), Pennsylvania Power Company (Penn Power)[1], PPL Electric Utilities Corporation (PPL), PECO Energy Company (PECO), UGI Utilities, Inc. – Electric Division (UGI), Allegheny Power Company (Allegheny Power), Energy Association of Pennsylvania (EAP), Pike County Light & Power Company (Pike County), and the IECPA.[2] The Commission also received comments on May 16, 2007 from the Independent Regulatory Review Commission (IRRC) and Senator Robert M. Tomlinson.

Our Proposed Rulemaking Order added a regulation at 52 Pa. Code §57.198 which proposed minimum standards regarding vegetation maintenance, pole, line, reclosers, sub-station inspections, maintenance and repair standards as well as directing EDCs to file biannually plans with annual updates in compliance with the minimum standards.

II. Discussion of General Comments

Comments of the Energy Association of Pennsylvania (EAP)

The EAP commented that the Commission has already mandated, by its existing regulations, reliability performance benchmarks that an EDC must satisfy and that this ensures a reliable distribution system. The Commission has numerous opportunities to review system performance through quarterly and annual reliability reports, customer complaints, customer satisfaction surveys and individual company meetings. Additionally, the Commission can review EDCs' Operation and

[1] Collectively, Met-Ed, Penelec and Penn Power are referred to as FirstEnergy.
[2] The IECPA et al. consists of Duquesne Industrial Intervenors, Met-Ed Industrial Users Group, Philadelphia Area Industrial Energy Users Group, Penelec Industrial Customer Alliance, PP&L Industrial Customer Alliance, and the West Penn Power Industrial Intervenors.

Maintenance practices through the mandated management effectiveness and operating efficiency audits that must be conducted not less than every eight years.

The EAP stated that the proposed rulemaking has moved forward without the industry expertise or cost/benefit analysis to support the requirements. The EAP estimates that if the proposed regulations are implemented, the added expense to Pennsylvania ratepayers over and above current inspection and maintenance practices will exceed at least $75 million per year with little or no assurance of improved electric service reliability. EAP alleges that proposal would increase the overall EDCs' operations and maintenance expenses 6.3% without a cost effective result for improving reliability. If mandated, the EDCs would eventually recover their increased operating costs through increased rates. EAP states that the needless increase in cost to the consumer could result in industrial job losses because of the increased electricity prices, the relocation of industry out-of-state, or not investing in present facilities.

EAP states that there are no studies to support a conclusion that the proposed standards will improve distribution service reliability to Pennsylvania customers. Also, the recently adopted regulations which tightened the Commission's monitoring of EDCs should be given a chance to work before additional needless regulations are imposed upon the EDCs.

Additionally, EAP claims that FERC has asserted jurisdiction over all EDC transmission plants. Promulgating regulations governing the transmission plant is legally impermissible, as it is outside the jurisdiction of this Commission. Mandated standards will exacerbate an EDC's trained worker resources shortage and will result in an increase in labor costs for EDCs because of the shortage of trained work force resources. Furthermore, the EAP alleges that 87% of tree-caused customer outages are caused by trees from outside the EDCs' right-of-way over which EDCs have limited control, and these proposed regulations would have no impact on decreasing these out-of-right-away outages. Thus, no substantial reliability would be improved.

Comments of the Pennsylvania Utility Contractors Association (PUCA)

PUCA commented to our Advance Notice of Proposed Rulemaking that it represents 300 contractors, subcontractors and suppliers throughout Pennsylvania and it believes standards should be established for repair and maintenance of EDC equipment or facilities critical for system reliability and for the safety of their workers.

Comments of Allegheny Power (AP)

AP commented that standardized industry-wide inspection and maintenance standards are not necessary in order for the Commission to ensure reliable electric delivery in Pennsylvania. AP agreed that it is appropriate for the Commission to require submittal of an EDC's individual plan of inspection and maintenance programs.

Comments of Wellsboro and Citizens'

Wellsboro and Citizens' jointly commented that they have voluntarily been replacing transformers and constructing transmission lines due to their obligations under the Public Utility Code to provide safe, adequate and reliable service to their customers and additional regulatory mandates for specific inspection, maintenance and repair or replacement activities should not be imposed. Citizens' and Wellsboro support the EAP's comments relating to desired flexibility in meeting reliability obligations rather than mandatory Commission-imposed cycles that may not result in cost-effective enhancements to service reliability.

Comments of UGI Utilities, Inc. – Electric Division (UGI)

UGI is a small EDC and it commented that the Commission should consider carefully the costs and benefits of its proposed regulations at a time when rate caps expire and the EDCs' costs will again be scrutinized. UGI notes that it has been a good performer in reliability indices reports and the proposed regulations would not necessarily have any impact on reliability for the company. Out of the total aggregate industry-wide increase in costs, UGI predicts its cost increase would be $2 million. The compliance cost would increase UGI's current maintenance expenses by 25% and cost recovery would cause UGI's transmission and distribution rates to increase by approximately 6%.

UGI states there is little evidence to indicate the proposed standards will benefit UGI customers and that the current reliability standards are sufficient to regulate UGI's performance. As an alternative to the proposed I&M standards, UGI proposes requiring the EDCs to submit biannual I&M plans which would enable the Commission to monitor the means by which EDCs are ensuring their compliance with the reliability benchmarks and standards without incurring unnecessary costs.

Comments of FirstEnergy

The FirstEnergy companies commented that the proposed standards hinder the EDCs' ability to implement an effective and cost-efficient plan based on the specific circumstances of the EDC. Not only will inspection and maintenance needs vary depending on the system configuration, design, equipment, customer density and condition of each EDC's system, but they will differ within pockets of a system. Further, the reliability benchmarks and standards provide the necessary motivation for EDCs to have adequate inspection and maintenance standards. Imposing additional standards is duplicative and costly.

Comments of Pike County

Pike County commented that the Commission does not have to adopt inspection and maintenance standards in order to ensure reliable electric delivery service in Pennsylvania. Instead of I&M standards, Pike County recommends the Commission establish certain broad reliability criteria and afford individual utilities the flexibility to meet such criteria in the most efficient, cost-effective manner. Any standards adopted by the Commission should not be in conflict with similar standards adopted by the Federal Energy Regulatory Authority (FERC) or the PJM Interconnection (PJM).

Pike claims that it is part of a multi-state system which has developed I&M programs internally based on history, practices, and experience. Tailoring its program to meet the proposed standards would be a costly and inefficient use of Pike County's resources according to Pike County. Pike does not support strict uniform I&M standards to assure reliable electric service. Pike argues an EDC's flexibility should be maintained for the development, modification and administration of I&M programs that not only impact reliability but efficiency as well.

Comments of Duquesne Light Company (Duquesne Light)

Duquesne Light supports flexible inspection and maintenance plans and related technology advancements that make strict standards obsolete. Duquesne Light supports the Commission's efforts to establish periodic I&M standards and is supportive of developing rules to support a flexible framework. Such plans should be submitted every two years for Commission review, comment and approval, and utilize the existing quarterly and annual reliability reports as a "timely" resource to monitor the activities at the EDCs to ensure that appropriate standards are currently being followed by the EDCs. Duquesne Light commented that the proposed regulations are wrong because more advanced diagnostics with more technical, condition-based, maintenance and life cycle analysis along with proven strategies and best practices should be utilized to improve reliability.

The IECPA, *et al.* comments.

The IECPA , *et al.* is comprised of ad hoc groups of large commercial, institutional, and industrial customers receiving electric service from various EDCs throughout Pennsylvania. Because members of IECPA use large amounts of electricity in their various production processes and operations, any changes to the electricity rates paid by these customers can significantly affect their overall costs of production. The IECPA, et al. urged the Commission to refrain from implementing any mandatory I&M requirements unless and until a cost/benefit test is performed. Specifically, IECPA, et al. agrees with the concerns raised by the EAP that if the proposed regulations are implemented, the added expense to ratepayers over and above current I&M program practices will exceed $75 million per year on a statewide basis with little or no assurance of improved electric service reliability.

While IECPA cares about reliability of service, it is concerned that the proposed regulations will significantly increase their rates without providing corresponding improvements in reliability. Only after the Commission has determined that the costs of applying these regulations to the EDCs will be equal to or less than the benefits that will be received by the customers should the Commission impose the additional regulations on the EDCs.

Comments of Senator Robert M. Tomlinson

Senator Robert M. Tomlinson commented on May 16, 2007, that the Commission's proposed regulation may bring an additional industry-wide aggregate cost of $75 million in assessments upon the Pennsylvania ratepayers as the EDCs claim, with little or no guarantee that there would be a direct benefit to reliability.

While he agreed that companies should file their inspection and maintenance plans, his interpretation of the LBFC study of June 2002 on reliability, is that the LBFC did not recommend the PUC adopt detailed and specific standards because all systems are not the same. The audit, however recommended an approach similar to Illinois whereby detailed documentation on programs are submitted. Senator Tomlinson believes this is a better approach as the regulations need to provide for EDCs to create the appropriate programs and integrate advances in technology into future inspection and maintenance plans. Further, companies not meeting the reliability standards can be ordered to improve reliability.

Comments of the Independent Regulatory Review Commission

The Independent Regulatory Review Commission (IRRC) commented that it is concerned about the fiscal impact of the minimum standards proposed in the regulations. The EDCs' claim that the proposed regulation would cost more than $75 million per year for Pennsylvania ratepayers is of concern when there is no identifiable direct benefit that can be attributed to the proposed regulation. IRRC stated that the Commission failed to submit information concerning costs imposed on the public and private sectors.

Further, IRRC comments that the need for such stringent regulations is not explained in detail. IRRC states that the Commission is already receiving significant information concerning EDCs' I&M programs and has acted upon some companies on a case-by-case basis. Therefore, there needs to be strong justification for an across-the-board regulation.

Also, IRRC commented that the EDCs have reported a loss of skilled technical talent in the electric industry and therefore their current taskforces may be insufficient to meet the needs of the regulation. It may take a few years for the EDCs to recruit, hire and train an adequate workforce that would bring them into compliance with the proposed regulation. If the PUC were to move forward with the regulation, it must address this concern and provide an adequate time period for the EDCs to come into compliance.

Regarding conflict with other regulations, IRRC notes that on March 16, 2007, FERC issued an order entitled "Mandatory Reliability Standards for the Bulk-Power System" for a final rule. FERC adopted vegetation management and is using the program developed by NERC. This program does not set forth specific inspection trim cycles but requires utilities maintain minimum clearances. Unlike the proposed regulation, it provides flexibility for utilities, EDCs or transmission owners to develop their own inspections schedules that are of "sufficient frequency to insure compliance with clearance requirements." The proposed regulation is stricter than the FERC rule for bulk power system of 100 kV or more.
IRRC requested a strong justification for this rulemaking to go forward.

Finally, IRRC commented that the EDCs need an adequate time period to come into compliance with I&M standards because they will need to recruit and hire adequately strained staff.

Comments of the Office of Consumer Advocate (OCA)

OCA commented that the Commission must establish inspection, maintenance, repair and replacement standards because this is required by Section 2802(20). The OCA acknowledges the standards should allow for flexibility to the EDCs in establishing and improving practices, and should allow an EDC to recognize the unique features of its transmission and distribution system. The OCA submits that adoption of a broad set of inspection and maintenance standards that set forth minimum requirements, coupled with submission and review of individual transmission and distribution maintenance plans will meet the desired goals. A broad set of minimum standards designed to promote high-quality service and a "best practices" approach is best.

OCA states that its proposed standards are designed to ensure that all critical facilities are reviewed and tested on a regular basis and that deficiencies are remedied in a reasonable time. OCA claims its standards neither limit the use of new technology nor innovation. Appropriate standards will ensure that proper attention is given to critical facilities and that techniques that can improve the efficiency of review, repair and operation are put into place. OCA argues EDCs can seek waivers from the Commission if the EDC has a particularly unique situation that would make compliance unduly burdensome. OCA's proposed minimum standards are in line with the union's proposed standards. OCA believes the EDCs should do more if required to maintain safe, adequate, reliable and reasonably continuous service.

OCA further comments the minimum standards must work in concert with any nationally established standards. That does not mean, however, that matters of Pennsylvania reliability need to rely exclusively on national standards as the EDCs suggest. The Commission is required to establish and enforce standards that meet Pennsylvania's requirements. Moreover, OCA states that FERC has expressed concerns over its authority to enforce its reliability standards and NERC remains a private organization that relies substantially on voluntary cooperation. The OCA also urges the Commission to consider the use of automatic fines and penalties as a means of enforcing compliance with these standards. We note that since the OCA's comment was filed, NERC has been certified as the ERO with legal authority to develop and enforce reliability standards for the bulk power system.

OSBA's Comments

OSBA recommends adding language to the proposed Section 57.198 which will state that the Commission's authority is not limited and that it can investigate and adjudicate the reliability of an EDC's distribution service regardless of how that reliability compares to the EDC's reliability on the effective date of 66 Pa. C.S. Chapter 28, and that the Commission still has the authority to reduce or deny a request for rate relief if the EDC has failed, is failing, or is likely to fail to provide adequate service. Further, OSBA recommends adding a subsection which states that an EDC's adherence to its plan shall not be construed to limit the Commission's authority to investigate under 66 Pa.C.S. §1501 and adjudicate the reliability of an EDC's distribution service, or under 66 Pa. C.S. §§523 and 526, to reduce, or deny a request for rate relief if the EDC has failed to provide adequate service.

Disposition of General Comments

A. Need for I&M Regulations

Electric service reliability is an essential and core regulatory responsibility of this Commission under the Public Utility Code. EDCs have a legal obligation to connect customers, and then provide them safe, adequate, and reliable service at reasonable prices and without unreasonable interruptions or delay. 66 Pa. C.S. § 1501. Moreover, as part of their public service obligation, EDCs are required to undertake prudent operational measures to prevent or avoid outages that are preventable at a reasonable cost, and to inspect, repair and maintain their facilities in a manner consistent with prudent utility practice.

The Electricity Generation Customer Choice and Competition Act ("Act"), 1996, Dec. 3, P.L. 802 No. 138 §4, became effective January 1, 1997. The Act amended 66 Pa.C.S. (Public Utility Code) by adding Chapter 28 to establish standards and procedures to permit direct access by retail customers to the competitive market for the generation of electricity, while maintaining the safety and reliability of the electric system. At the same time, the Act authorized the Commission to ensure that the levels of reliability that were present prior to the restructuring of the electric utility industry would continue in the new competitive environment. 66 Pa. C.S. §§ 2802(12), 2804(1) and 2807(d). This Commission enforces nationally accepted CAIDI, SAIFI and SAIDI reliability indices standards.[3] These are defined in detail in our regulations and in our order entered April 15, 2004 *Amended Reliability Benchmarks and Standards for the Electric Distribution Companies,* M-00991220, April 15, 2004.

However, in the Commission's judgment, the establishment of reasonable and flexible I&M standards for EDCs will further enhance and will be an important tool to ensure adequate reliability, as required by law. In addition, we cannot ignore the explicit statutory language contained in the Act which also links the reliability of electric service with the establishment, by regulation, of inspection and maintenance standards. Specifically, 66 Pa. C.S. § 2802(20) provides:

> (20) Since continuing and ensuring the reliability of electric service depends on adequate generation and on conscientious inspection and maintenance of transmission and distribution systems, the independent system operator or its functional equivalent should set, and the Commission shall set through regulations, inspection, maintenance, repair, and replacement standards and enforce those standards.

[3] SAIFI (System Average Interruption Frequency Index) is the number of sustained interruptions experienced by an average customer on the system. SAIDI (System Average Interruption Duration Index) is the number of minutes of sustained interruption experienced by an average customer on the system. CAIDI (Customer Average Interruption Duration Index) is the average duration of a sustained interruption experienced annually by a customer on the system. This is measured in minutes. As the indices figures rise, it indicates poorer performance.

66 Pa.C.S. §2802(20). Further, Section 1501 of the Public Utility Code requires every public utility to furnish and maintain adequate, efficient, safe and reasonable service and facilities, and to make all such repairs, changes, alterations, substitutions, extensions and improvements in or to such service and facilities as shall be necessary or proper for the accommodation, convenience, and safety of its patrons, employees, and the public. Such service shall be reasonably continuous. 66 Pa. C.S. §1501. Thus, both Section 1501 in general and Section 2802(20) in particular support the establishment of I&M standards by regulation.

Additionally, in the wake of the August 14, 2003 blackout, the Federal Energy Regulatory Commission ("FERC") commissioned a study of utility vegetation management practices and this led to a report entitled "Utility Vegetation Management Final Report" prepared by CN Utility Consulting, LLC and released by FERC in March, 2004. The report concluded that current oversight of utility vegetation management activities by appropriate agencies or organizations was overwhelmingly inadequate and the report recommended the adoption of vegetation management best practices, schedules and the achievement of reductions in tree-related outages. Report, pp. 68-69. While this report is not binding upon this Commission, we consider it in determining whether to establish I&M standards. We also consider the fact that other states like California, Missouri, New York, Connecticut, and Ohio have I&M standards in place.

Finally, we observe that the quarterly and annual reporting requirements under 52 Pa. Code §57.195 are not a substitute for inspection and maintenance standards within the meaning of Section 2802(20). The reporting requirements at Section 57.195 of the Pennsylvania Code require EDCs to provide the Commission with inspection and maintenance goals and quarterly reports as to the EDCs' progress in meeting these goals. The establishment of reasonable and flexible I&M

standards will provide EDCs with a better understanding of what goals are acceptable to the Commission for their periodic reports and will help EDCs meet these goals. Also, I&M standards are not the same as the reliability indices and standards used to measure current performance. I&M standards are focused on ensuring future reliability and are broader in scope.

For these above-stated reasons, this Commission rejects comments suggesting that I&M standards are not necessary for Pennsylvania.

B. Approach for I&M Regulations

While the Commission finds that the establishment of I&M standards is necessary, the Commission takes seriously the position of the industry that the I&M regulations should not mandate inspection and inspection intervals that, for a given EDC, are not prudent or would not be cost/benefit justified. The EAP's and EDCs' comments suggest that the costs associated with proscriptive I&M regulations outweigh the benefits of assuring reliability does not deteriorate from service levels in 1997. However, although the EAP claims that the aggregate cost of compliance with the I&M standards in the proposed-form regulations would be $75 million, there are few details to support this estimate at this time. In addition, we observe that the total intrastate revenues for this industry in calendar year 2006 was $11.6 billion. Thus, the $75 million figure, even if sustainable, is about 0.6% of this total.

The EDCs, Senator Tomlinson, and IRRC raise the point of a cost/benefit analysis. As noted above, we concur, in general, that I&M regulations should reflect cost/benefit concerns. As explained in a recent paper published by the National Regulatory Research Institute (NRRI), an efficient outage policy depends on the value to customers of avoiding a utility outage, as well as the cost to the utility to take reasonable steps to prevent avoidable outages. When an outage occurs, the question then is the value to customers of minimizing its duration and extent, and the cost to the utility of doing so. An efficient policy is one that reflects and achieves a reasonable relationship between the cost and benefit to the customer. *Regulatory Policies for Electricity Outages: A Systems Approach, August*, 2007, paper published by The National Regulatory Research Institute.

Industrial and commercial customers tend to be more sensitive to and experience greater damage from outage frequency because they are more reliant on digital circuitry in their industrial processes, office equipment and appliances. A power supply disturbance such as a voltage sag, surge, transient or harmonic can result in the customer experiencing an interruption in service, and machines on a manufacturing line can go off, and product and time is lost for the business. Interruption in service can also be a dangerous situation for some companies like chemical plants, hospitals, and airports.

Residential customer outages over eight hours result in loss of heat, air conditioning, use of elevators, and food spoilage. In practice, the calculation of outage costs and outage probabilities is difficult. Different customers in the same class and use category may assign very different costs to outage. NRRI paper at 5. At the technical conference, there was no offering by any party regarding customer survey data to show what values the customers place on reliable service. Neither was there any evidence presented to show the EDCs' costs for pre-outage prevention regarding vegetation management, transmission and distribution facility inspection and replacement and identification and correction of poorly performing circuits.[4]

[4] Anecdotal information is available showing that EDCs have cost/benefit data. PECO was quoted in a recent news article as having recently spent $1 million on squirrel guards to stop outages from squirrels. As a result, PECO reports its squirrel-related outages have fallen from 11,605 in 2003 to 1,345 in 2006. http://www.usatoday.com/news/nation/2007-03-11-suicide-squirrels_N.htm.

We recognize that this is a technology-based industry, and as such, our regulatory policies should be flexible in order to encourage a utility to take advantage of technological advances to bring better service to customers at a lower price. An example of technological advancement is the use of satellites for instant communications as part of the system's monitoring. Creosoted utility poles generally last longer and require less frequent inspections initially than wooden poles. Infra-red monitoring of lines is also a technological improvement over foot patrols.

The exact cost to benefit ratio of implementing any specific I&M standard is still unknown and we do not endorse, at this time, any specific model to determine that ratio. To date, the EDCs discussed general cost figures, but none of their presentations were supported by written documentation offered as evidence at the presentation at the technical conference. The EDCs have alleged that the proposed-form regulations would impose exorbitant cost increases to the EDCs without any measurable or guaranteed betterment of reliability of service. However, these estimates do not address the value customers assign to outage avoidance, nor do they address cost savings the EDCs may have experienced due to cuts in staffing or maintenance, since under a rate cap regime cutting staff and deferring maintenance can be ways to increase net income. OCA stated that it was not able to refute the $75 million aggregate incremental cost increase because OCA did not know the details of how the figure was calculated.

Scott Rubin, Esquire, counsel for AFL-CIO-Utility Caucus, stated at the technical conference of January 22, 2007:

> The EDCs combined have I think laid off in excess a thousand people in the last ten years. They've drastically reduced their maintenance and inspection budgets. So we don't view that $75 million as being a terribly significant figure spread out across Pennsylvania, and it

> appears to us that the EDCs have saved substantially more than that through work force reductions and the elimination or drastic reduction of preventive maintenance.

Technical Conference of January 22, 2007, Scott Rubin, p. 19. If the EDCs cut costs including work force and I&M routines after the Act was passed in order to increase net income, their claim that the cost to perform within the proposed draft standards is unpersuasive as they should not have been cutting reasonable inspection and maintenance costs which result in deteriorating service.

We have also observed that in the year 2006, six EDCs (Met-Ed, Penelec, Penn Power, PPL, Pike County and Wellsboro) failed to achieve their rolling three-year SAIFI performance standard. SAIFI measures system-wide average frequency of outages. In 2006, three EDCs (Allegheny Power, Penelec and Penn Power) failed to achieve their rolling three-year CAIDI performance standard. CAIDI measures average duration of customer outages. On the positive side, all EDCs complied with the 12-month CAIDI performance standard and six (Duquesne Light, Penelec, UGI Electric, Citizens, Pike County and Wellsboro) of eleven EDCs performed better than their CAIDI benchmark last year, so that shows some improvement in average performance since 1997.

However, most recently, we have seen some EDCs report indices higher than their rolling 12-months ending December 31, 2007 reliability standards. Specifically, Allegheny Power reported higher indices than all three standards including: CAIDI, SAIFI and SAIDI Penn Power reported indices higher than their rolling 12-month CAIDI standard. Met-Ed and Penelec reported higher indices than their SAIFI standards. These recent reliability performance statistics also support the need for further enhancements to our regulatory efforts to ensure the level of service quality required by law. This Commission published in July, 2007 a report entitled, *Electric Service Reliability In Pennsylvania: 2006.* Attached to this Final Rulemaking Order are excerpt tables from the report showing each EDCs' performance reliability indices and how they measured against their respective 12-month and 3-year rolling standards. *See Attachment A (Table 12-Month Average Electric Reliability Indices for 2006) and B (Three-Year Average Electric Reliability Indices for 2004-2006).*

On July 3, 2002, at M-00021619, this Commission's Bureau of Conservation, Economics, and Energy Planning (CEEP) prepared an Inspection and Maintenance Study which was adopted by the Commission. This study found that the major causes of service outages in 2000 were attributable to equipment failure and tree-trimming related outages. Each reason accounted for about 22% of the total outages the EDCs were experiencing. This conclusion was based upon information provided to CEEP from the EDCs. These types of outages are arguably within the control of the EDCs. Both types of outages are being addressed in Annex A.[5]

EAP have cited to industry statistics that of the tree-trimming related outages, approximately 85% at a minimum are caused by trees outside the utility right-of-way and that there is difficulty in negotiating with the landowners of said danger trees. Robert Stoyko, Vice President, Electric-Division – UGI Utilities, technical conference January 22, 2007 transcript p. 26; David E. Schleicher, General Manager Transmission/Distribution PPL Electric Utilities, Corp., p. 70. Some of the utilities negotiate with property owners to remove off-right-of-way trees posing a danger of outages. Wayne Honath, Manager, Reliability and Standards Duquesne Light

[5] Additionally, at the January 22, 2007 technical conference, we asked the industry to provide us with their internal inspection, maintenance and repair standards prior to the Electric Competition Act of 1997. Responses to this request were received and they are incorporated in tables throughout this order regarding each individual standard.

Company, Transcript p. 37. PPL's presenter, David Schleicher, admitted PPL is looking at reducing their tree trimming cycle from 5 years urban and 8 years rural to 5 years across the board and they are looking at the cost per SAIDI minute of downtime to justify the expense. Transcript at p. 71.

However, we can and should balance the possible rise in operating costs for any given inspection and maintenance approach against the savings to customers in avoiding outages, especially black-outs covering multiple states, and very high numbers of outages over a longer period of time. In the Final Report on the August 2003 blackout, the Task Force concluded that the blackout, caused in part from inadequate vegetation management, had an economic cost of between $4 billion and $10 billion in the United States alone. Canada also sustained a partial black out. This economic impact on businesses and citizens in the U.S. and Canada, and approximately 55,000 residents of Pennsylvania, was significant. A business that loses power can quickly lose sales revenues and the ability to produce its product. Loss of power is a health and safety issue as well as a financial issue.

The OCA allocated the estimated $75 million aggregate cost over the 11 EDCs operating in Pennsylvania. Putting that estimate into the context of operating budgets and maintenance budgets of $75 to $100 million for some of the largest utilities (those total revenues approaching or in excess of $1 billion), the incremental cost increase did not appear to outweigh the need for I&M guidelines. Also, OCA attempted to calculate the cents per kilowatt-hour impact of the $75 million estimate over all of the kilowatt-hours sold in Pennsylvania in 2005, and it comes out to .05 cents per kilowatt-hour, or a half a mill per kilowatt-hour sold. For an average residential customer using 750 kilowatt-hours per month that is 35 cents per month. Technical Conference Hearing transcript Tanya McClosky, p. 9.

Several other states have now established I&M standards in the wake of electric deregulation. On March 31, 1997, the California Public Utilities Commission adopted minimum requirements for electric distribution facilities, regarding inspection (including maximum allowable inspection cycle lengths) condition rating, scheduling and performance of corrective action, record-keeping, and reporting, in order to ensure safe and high-quality electrical service, and to implement the provisions of California's statute, Section 364 of Assembly Bill 1890, Chapter 854, Statutes of 1996. California requires annual compliance plans for the inspection and record-keeping by no later than July 1 of each year. The report identifies the number of facilities, by type which have been inspected during the previous period. It must identify those facilities which were scheduled for inspection but which were not inspected according to schedule and shall explain why the inspections were not conducted, and a date certain by which the required inspection will take place. The report also presents totals and the percentage of equipment in need of corrective action, but with a scheduled date beyond the reporting period.

California has minimum standards for three levels of inspection: (1) patrol, meaning a simple visual inspection; (2) detailed, meaning taking the equipment apart and examining each piece for inspection; and (3)intrusive, involving digging up soil to test below soil level as in inspection of poles.

California has maximum intervals of 1-2 years for transformers (patrol inspection) and 5 years for detailed inspections. Overhead conductors and cables have a maximum inspection interval of 1-2 years for patrol and 5 years for more detailed inspections. Wood poles which passed intrusive inspection have a maximum interval for intrusive inspection every 20 years. Wood poles under 15 years, just have a 1-2 year patrol interval, and wood poles over 15 years which have not been subject to intrusive inspection, 1-2 years patrol inspection plus an intrusive inspection at least once every ten years.

On October 2, 2007, the Missouri Public Service Commission (MoPSC) filed a Proposed Rulemaking adopting 4 CSR 240-23.030 – Electrical Corporation Vegetation Management Standards and Reporting Requirements. MoPSC limited the adoption of outside standards, guidelines and procedures to three times: ANSI A300 (Section (4)(A)(2)), which contains standards for vegetation management, ANSI Z133.1 (Section (4)(A)(5)), which contains guidelines for personnel safety, and the National Electric Safety Code (Section (4)(A)(9)), which contains standards for public safety.

MoPSC stated that if the authorities conflict, the EDC should file notice of the EDC's resolution for the conflict and the basis for it. Missouri addressed claims of excessive high costs to comply with proposed regulations. MoPSC altered its proposed rule to lower the cost of compliance and provided a mechanism through which utilities may record the costs associated with compliance and eventually recover the costs in rates. It stated as follows in its proposed regulation:

> (4) In the event an electrical corporation incurs expenses as a result of this rule in excess of the costs included in current rates, the corporation may submit a request to the Commission for accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from its next general rate case, filed after the effective date of this rule, using a tracking mechanism to record the difference between the actually incurred expenses as a result of this rule and the amount included in the corporation's rates, or if there is no identifiable amount included in the corporation's rates, the amount reflected in the appropriate accounts for infrastructure inspection and maintenance on the corporation's books for the test year (as updated) from the corporation's last rate case will be used to determine the amount

> included in current rates. In the event that such authorization is granted, the next general rate case must be filed no later than five (5) years after the effective date of this rule. Parties to any electrical corporation request for accounting authorization pursuant to this rule may ask the commission to require the electrical corporation to collect and maintain data (such as actual revenues and actual infrastructure inspection expenses) until such time as the commission addresses ratemaking for the deferrals. The commission will address the ratemaking of any costs deferred under these accounting authorizations at the time the electrical corporation seeks ratemaking in a general rate case.

The Missouri Commission also provided for variances in its rulemaking. The EDCs were allowed to propose and the Commission to approve an alternative infrastructure inspection program varying from the table "Electrical Corporation System Inspection Cycles (Maximum Intervals in Years)." If the EDC can establish that the alternative inspection program has previously produced equal to or greater reliability performance than what would be produced under the rule, or that the alternative infrastructure inspection program shall produce equal to or greater reliability performance in the future than what would be produced under the rule, then a variance may be granted for good cause shown.

Missouri proposed maximum intervals of 4-6 years for patrol inspections of wood and non-wood poles and overhead structures, 12 years for detailed inspections of non-wood poles, and 12 years for intrusive inspections of wood poles. Regarding conductors, transformers, reclosers, regulators, capacitors, switching/protective devices, and street lighting, 4-6 years patrol inspections for overhead, and 8-12 years detailed inspections for overhead. Underground-direct buried and conduit had 4-6 year patrol inspections and 8-12 year detailed inspections. Manholes, vaults, tunnels and other underground structures had a 4-6 year maximum interval for patrol inspections, and an 8-12 year maximum interval for detailed inspections.

We are influenced by what states like Missouri and California are doing regarding establishing inspection and maintenance standards. Like Missouri, we find that the alternative of using a reliability-based trimming plan is reasonable under certain circumstances and we will add language to the proposed rulemaking to clarify that utilities may propose a plan that uses intervals outside the standards in lieu of a plan that adheres to the rule, but it must be explained, and the reliability indices that the EDCs are reporting as well as an EDC's prior internal I&M standards will be taken into consideration in approval or rejection of the plan. This change is reflected in subsection (c).

Regarding the issue of whether we have jurisdiction to establish standards regarding transmission lines, it is well-settled that the Commission has concurrent jurisdiction over transmission lines with FERC. The U.S. Supreme Court in *New York v. FERC,* 535 U.S. 1 (2002), recently reiterated that no federal agency has the power to act, let alone preempt the validly enacted legislation of a sovereign state, unless Congress confers such power upon it manifesting clear Congressional intent to so preempt. 152 L.Ed. 2d at 62-63 (citation omitted). The Supreme Court has unequivocally held "States retain significant control over local matters even when retail transmissions are unbundled." *Id.* 152 L.Ed.2d at 66.

States have authority over transmission facilities constructed within their borders. States authorize the construction of the transmission facilities and issue certificates to utilities to operate them. The long-standing state authority is preserved by the Federal Power Act (FPA) and cannot be preempted by FERC's actions. Thus, this Commission is fully within its rights in establishing I&M guidelines regarding transmission lines. However, because FERC is in the process of implementing inspection, maintenance, repair and replacement standards regarding transmission wires, we elect not to exercise our concurrent jurisdiction at this time, and will not promulgate regulations regarding transmission lines.

Similar to Missouri, we will abstain from establishing I&M standards at this time regarding high voltage transmission lines in deference to the federal government's current reliability rulemaking regarding transmission lines. This addresses IRRC's comment that the Proposed Rulemaking seemed more stringent than the FERC rule for bulk power systems of 100 kV or more. Thus, the EDCs will have more flexibility regarding tree-trimming cycles and inspection, repair and replacement intervals regarding transmission lines.

As noted above, the Commission takes seriously the position of the industry that the I&M regulations should not mandate inspection intervals that, for a given EDC, are not prudent or would not be cost/benefit justified. However, given our obligations under law to ensure electric service reliability, the relative costs involved, and the deteriorating service performance of some EDCs in recent years, we are persuaded that flexible I&M standards should be established by this final rulemaking order. Therefore, in addition to mandating reports regarding transmission and distribution inspection and maintenance plans and the CEEP review/approval process for those plans, this rulemaking will establish flexible I&M standards based upon current industry practices. The I&M schedules will be part of each EDC's annual plan and they must be consistent with the I&M standards established in these regulations.

However, the regulations will allow the individual EDCs to deviate from the standard set forth in the regulation, provided that such deviation/alternative can be justified based on utility-specific circumstances, and a cost/benefit analysis. In this fashion, where compliance with a given I&M standard for a specific EDC would not be prudent or cost/benefit justified, the EDC may deviate from that standard provided that it can adequately justify that different I&M interval or approach. As such, the regulation will provide the leeway necessary for EDCs to avoid unnecessary costs. Further, Commission staff's initial rejection of an I&M plan in whole or in part, can be appealed to the full Commission via 52 Pa. Code §5.44.

In sum, the Commission finds that using a broad set of minimum standards as proposed in OCA's comments, will promote high quality service and reliability, as required by law, without forcing an EDC to comply with a given I&M benchmark that is not cost/benefit justified for its particular service territory.

Finally, IRRC commented that the EDCs need an adequate time period to come into compliance with I&M standards because they will need to recruit and hire adequately trained staff. We will give the first group of EDCs until October 1, 2009 to file their first biennial plan with the Commission. The plan will cover inspection, maintenance, repair, and replacement plans for calendar years 2011 and 2012. The remaining EDCs in a second group shall be required to file their first biennial plans on October 1, 2010. Their plans will cover inspection, maintenance, repair, and replacement plans for calendar years 2012 and 2013.

With this procedural schedule, the Commission will have enough time to review and approve the plans. Implementation of the approved plans will occur 15 months after the plan filing deadline. With this 15-month interval, if there are amendments that need to be made to the plans, the EDCs will have adequate notice before the implementation date, and can adjust their financial budgets and operational plans accordingly. The EDCs will then continue to file in staggered years, every two years from the date upon which they first filed. We believe this process provides adequate time to comply or explain why they cannot immediately comply with a given standard. The specific EDCs that are in Groups 1 and 2 will be defined by implementation order after this rulemaking is effective.

III. Comments Regarding Specific Sections

Section 57.192. Definitions.

IRRC commented that the definitions of rural area and urban area are problematic. Similarly, many EDCs also stated there is no need for this distinction. The EAP stated that individual EDCs may, for their own vegetation management purposes, designate distribution circuits, or portions thereof, as either "urban" or "rural"; however, there is no value in requiring all EDCs to distinguish between rural areas and urban areas, either by a population threshold of 5,000 or any other means because many distribution circuits cross between proposed urban and rural areas. One circuit may cross multiple times into rural and urban areas. Therefore the request is not practical and no other state Commission makes such a distinction.

The EAP commented that the distinction between urban and rural areas adds no value since circuits can cross many times between rural and urban areas. PPL commented that it classifies any distribution circuit that has an average of 35 or more customers per circuit mile as "urban" and those with fewer than 35 customers as rural. As of February, 2007, PPL Electric has 9,600 circuit miles of overhead urban circuits, and 17,700 circuit miles of overhead rural circuits. PPL does have different company-wide standards for vegetation management. For distribution lines, rural areas are on an 8-year trimming cycle and urban are on a 5 year cycle. Other internal standards appear to be the same for both rural and urban areas.

FirstEnergy commented that it does not believe that EDCs should be required to distinguish between rural versus urban in its plans. While systems that are rural may differ from systems that are urban, to draw distinctions based on the definitions provided in the proposed rulemaking would be arduous and costly with little to no benefit to be realized. Additionally, a single circuit can cross between rural and urban areas multiple times. The companies do not distinguish their systems based upon the population threshold of five thousand and FirstEnergy encourages the Commission to eliminate this designation in any final rules.

Allegheny Power commented that urban/rural census definition is not appropriate for planning transmission and distribution inspection and maintenance activities. Line equipment (reclosers, transformers, conductor, fuses, etc.) functions in the same manner regardless of an urban setting or rural setting. Inspection and maintenance practices are the same regardless of population density. Similarly, pole inspection cycles are independent of population density. Vegetation management cycles may be tailored to the needs of cities or towns. The cycle and practice differences are typically governed by agreements with individual municipalities and are independent of discrete population size boundaries. Allegheny Power has many long circuits that cross into "urban" and "rural" areas often several times. Tailoring work practices to portions of individual circuits is inefficient and does not promote improvement.

Duquesne Light sees no legitimate reason for distinguishing between urban versus rural circuits. The standards proposed for maintenance intervals are not dependent on whether the circuits are rural versus urban. Duquesne does not distinguish its plans between communities with a population of less than 5,000 people and those having a population of 5,000 or more.

Pike County commented that it does not support the urban vs. rural concept. However, since the entire Pike service territory is predominantly rural and less than 5,000 customers anyway, Pike County believes it should only have to submit one plan for the whole service territory.

The OSBA commented that population density is a better measure than total population and the OSBA noted that the General Assembly is considering House Bill 2347 which would codify a uniform definition of "rural area" and by implication "non-rural area." Accordingly, the OSBA recommended the Commission revise the proposed definitions in Section 57.192 to reflect HB 2347.

Disposition

Given the above comments, we will eliminate the rural/urban definitions as only PPL appears to differentiate its standards between rural and urban areas at this time, and that is only with regard to one internal standard regarding the distribution line tree trimming practices.

Section 57.198 Inspection and Maintenance standards

Subsection (a). This subsection states that an EDC shall have a plan for the periodic inspection and maintenance of poles, overhead conductors and cables, wires, transformers, switching devices, protective devices, regulators, capacitors, substations and other facilities critical to maintaining an acceptable level of reliability in a format the Commission prescribes. The Commission may require an EDC to submit an updated plan at any time containing information the Commission may prescribe.

IRRC states that the first sentence in Subsection 57.198(a) is long and confusing. It contains a list of ten specific items to be included in the I&M plan and the words "other facilities critical to maintaining an acceptable level of reliability." To improve clarity, it should be enumerated. Additionally, IRRC commented that the examples of the type of equipment or facilities ought to be provided. We will comply with IRRC's suggestion to enumerate the specific items to be included in the I&M plan. We will eliminate the phrase "other facilities."

Further, IRRC questioned when and how will the EDCs be notified of the prescribed format the Commission wants to see in the plans. Format requirements will be addressed in a Secretarial Letter that will be issued by the Commission to the EDCs prior to the date the first plan is due.

The second sentence of subsection (a) states: "The Commission will review each plan and may issue orders to ensure compliance with this section." The intent of this sentence is unclear according to IRRC and it appears to be redundant and should be deleted.

IRRC further commented that the final sentence of Subsection (a) states that the PUC "may require an EDC to submit an updated plan at any time containing information the Commission may prescribe." IRRC is unclear how and when the PUC would notify an EDC to update its plan. Under what circumstances, would it be necessary to update a plan? How would the PUC notify the EDC of the information that the PUC is prescribing be contained in the plan? After the EDC submits its updated plan, when would the PUC notify the EDC that the update was approved?

Disposition

Subsection (a) shall be revised to state:

> (A)*Filing date and plan components.* Every 2 years by October 1, each EDC shall prepare and file with the Commission a biennial plan for the periodic inspection, maintenance, repair, and replacement of its facilities that is designed to meet its performance benchmarks and standards pursuant to 52 Pa. Code §§ 57.191 – 57.197. EDCs in compliance group 1, as determined by the Commission, shall file their initial plans on October 1, 2009. EDCs in compliance group 2, as determined by the Commission, shall file their initial plans on October 1, 2010. Each EDC's biennial plan shall cover the 2 calendar years beginning 15 months after filing, be implemented 15 months after filing, and shall remain in effect for 2 calendar years thereafter. In preparing this plan, the following facilities are critical to maintaining system reliability: (1) poles. (2) overhead conductors and cables. (3) transformers. (4) switching devices (5) protective devices. (6) regulators. (7) capacitors. (8) substations.

IRRC's suggested numeration is followed. We are grouping the EDCs into two compliance groups and staggering their filing deadlines to facilitate timely administrative review. The plans will cover the two calendar years beginning 15 months after filing because the EDCs requested the plans be amended well in advance of implementation dates so that budgets may be adjusted accordingly.

Subsection (a)(1) – Industry codes, rural and urban areas; I&M intervals

Subsection (a)(1) begins with the statement that the I&M "plan must be based on industry codes, national electric industry practices, manufacturers' recommendations, sound engineering judgment and past experience." IRRC questioned to which industry codes and national electric industry practices did the Commission refer. If the Commission meant the National Electricity Safety Code or code and practices of organizations such as the Institute of Electrical and Electronic Engineers and NERC, then the appropriate codes or organizations should be referenced in the final-form regulation. We agree with this suggestion, and the changes shall be incorporated in Section 57.198(b).

IRRC states that the phrase "sound engineering judgment" is vague since engineers may respectfully disagree on what is sound. It is IRRC's understanding that the PUC will determine whether a plan is based on reasonable or sound engineering judgment. Hence, it will be a part of the PUC review of plans under Subsection 57.198(h) and if the PUC identifies problems in the plan, it will notify the EDC of the plan's deficiencies pursuant to Subsection 57.198(j). Therefore, it is not necessary to include the words "sound engineering judgment" in the regulation, and IRRC recommends this phrase be deleted. We will adopt IRRC's recommendation.

The final sentence in Subsection (a)(1) states: "The plan must take into account the broad minimum inspection and maintenance intervals provided for in subsection (e)." IRRC questions why the word "broad" is used in this sentence. Since the provisions in new subsection (n) set very specific minimum intervals, the use of the word "broad" is confusing. The word "broad" will be deleted.

Subsection (a)(1) states that the plan shall be based on industry codes, national electric industry practices, manufacturers' recommendations, sound engineering judgment and past experience. The plan shall be divided into rural and urban areas. The plan shall take into account the broad minimum inspection and maintenance intervals provided for in subsection (e).

AFL-CIO commented that Section 57.198(a)(1) should be revised to state:

> The plan must be based on industry codes, National electric industry practices, manufacturers' recommendations, sound engineering judgment and past experience. The plan must be divided into rural and urban areas. The plan must ~~take into account~~ comply with the ~~broad~~ minimum inspection and maintenance intervals ~~provided for~~ set forth in subsection (e).

AFL-CIO believes these changes are necessary to ensure that all EDCs in Pennsylvania meet at least minimum I& M standards. EDCs should not be permitted to submit plans that do not meet these minimum requirements. AFL-CIO advocates all EDCs must meet the minimum standards. After considering the EDCs comments regarding the increased costs, differing I&M plans and claims that reliability will not necessarily increase if mandatory minimum I&M standards are applied to large and small EDCs alike, as explained previously, the Commission will adopt minimum I&M standards, but will also include flexibility to allow EDCs to deviate from the I&M standard provided the deviation can be justified by the EDC's unique circumstances or a cost/benefit analysis to support an alternative approach that will still support the level of reliability required by law. Accordingly, we will change the language in (a)(2), now (c) to state as follows:

> The plan shall comply with inspection and maintenance standards set forth in subsection (N). However, an EDC may propose a plan that, for a given standard, uses intervals outside the Commission standard, provided that the deviation can be justified by the EDC's unique circumstances or a cost/benefit analysis to support an alternative approach that will still support the level of reliability required by law.

OCA commented that §57.198, Inspection and Maintenance Standards, should be amended to state that the plan should specify all applicable hardware standards, all applicable operation standards, routine maintenance requirements, emergency maintenance plans and procedures for coordinating with other interconnected systems. We agree in part, and will add the routine inspection and maintenance requirements and emergency maintenance plans and procedures portion of OCA's suggested specifications in the regulation at subsection (d).

EAP commented that the EDCs need flexibility in determining when vegetation management work must be conducted. Mandating a uniform four-year tree-trimming cycle for distribution lines accomplishes very little toward improving service reliability. EAP commented that line clearance is a condition-based activity. Each EDC schedules tree-trimming on its circuits based upon its own individually established criteria. Typically the proximity of tree branches to the wires, the number of customers fed by the circuit, the number of tree-caused outage events recently experienced on the circuit, and the elapsed time since last trimmed are considered.

According to EAP, trimming too soon results in wasting part of the value of the work done during the last trimming; trimming too late results in poor circuit performance. Cycle length and clearances, have less influence on service reliability, especially in regards to on-right-of-way vegetation caused service outages compared to off-right-of-way trees falling into the lines. California's no contact requirement is not for reliability reasons according to EAP, but rather to avoid sparking from tree contact that could cause wildfires during their dry season. EAP states that Pennsylvania does not need this requirement. Pennsylvania has drought conditions during the summer months at times also. We are persuaded to change the tree-trimming cycle standard and allow for up to 8 years for a vegetation management standard instead. This will account for the varying EDC practices and service territory terrains. However, intervals longer than 8 years will require justification and be supported by a cost/benefit analysis.

Finally, to clarify the industry codes and practices that should be followed in developing each EDC's plan, we have decided to change (a)(1) to (b) and it shall state that the plan shall be consistent with the National Electrical Safety Code, Codes and Practices of the Institute of Electrical and Electronic Engineers, FERC Regulations, and the provision of the American National Standards Institute, Inc.

Subsection (a)(2) – Adequate resources.

Subsection (a)(2) states that an EDC shall reduce the risk of future service interruptions by accounting for the age, condition, design and performance of system components and by providing adequate resources to maintain, repair, replace and upgrade the system.

IRRC asks how the PUC will determine if an EDC has provided adequate resources to maintain, repair, replace and upgrade its system. We will delete "adequate resources" from the final regulation.

The new subsection (c) shall state that the plan shall comply with inspection and maintenance standards set forth in subsection (n).

Subsection (a)(3) – Vegetation clearance program

This subsection requires that the EDC's I&M plan "include a program for the maintenance of minimum clearances of vegetation from the EDC's overhead transmission and distribution facilities sufficient to avoid contact under design-based conditions." EDCs questioned the need for this provision and called it unreasonable. Incidental contact with vegetation or tree branches does not necessarily cause outages. Given the growth of some trees, this requirement could actually force some EDCs to perform trimming annually and would greatly increase costs with no quantifiable benefit. IRRC commented that the PUC needs to explain the basis and intent for this requirement.

The Commission was concerned that vegetation contact could cause the circuit to overheat and shut off. The blackout report mentioned tree contact with transmission lines played a role in the circuits shutting down and the ultimate blackout of August 14, 2003. However, requiring EDCs to trim trees more frequently than necessary, may end up costing the EDC and consumer more money without a substantial improvement in reliability. If there is a wider differential between electric rates in Pennsylvania than other states, that may have a negative impact on attracting or keeping businesses to operate in our state. We will remove the language "sufficient to avoid contact under design-based conditions."

PECO commented that the Commission should amend proposed Section 57.198(a) to remove subsection 3's requirement for a plan for trimming off right-of-way trees. FirstEnergy commented the phrase "may cause" is too vague and open ended when coupled with the requirement to trim off of a right-of-way. PECO has limited authority to trim or remove trees that are outside of the right-of-way.

PECO recommends adopting Connecticut's approach. PECO recommends Section 57.198(a)(3) be amended to state:

> The plan shall include a program for the maintenance of minimum clearances of vegetation from the EDC's overhead transmission and distribution facilities sufficient to avoid contact under design-based conditions. The plan shall include a program for the trimming of tree branches and limbs located in close proximity to overhead electric wires when the branches and limbs may cause damage to the electric wires.

We will eliminate the last phrase "regardless of whether the trees in question are on or off of a right of way." We will keep the "may cause" language as it is similar to Connecticut's approach.

Subsection (a)(4)

IRRC commented that Subsection 57.198(a)(4) refers to quarterly and annual reliability reports from an EDC. If these are the reports required by the existing provisions at Sections 57.193(c) and 57.195, then the proposed regulation should include cross-references to these existing provisions. We agree with IRRC and will amend this section into subsection (h) such that references are made to the other sections.

Subsection (b) – Plan review process

This subsection requires EDCs to submit their initial I&M plans by October 1, 2008. The EDCs and IRRC believe that there are not sufficient numbers of trained and experienced people available to meet the I&M schedules set forth in Subsection (e). They claim it will take years to recruit and train an adequate workforce to implement the proposed regulation. If the prescriptive requirements in proposed subsection (e) are retained in the final-form regulation, the Commission should carefully examine whether the October deadline is achievable.

In consideration of these comments, the deadline will be changed to October 1, 2009 for group 1 and October 1, 2010 for group 2, and every other year thereafter to allow EDCs time to recruit and train necessary workers. IRRC seeks clarification on the submission of the whole 1-year plan every two years. We will amend subsection (b) and make the plan cover the two calendar years that follow 15 months from the filing date. Thus, a two-year period of plans will be covered in each Commission review. This language will be in Section 57.198(a).

Subsections (b) and (c) – Designee

These subsections set forth the process for EDCs to submit plans and revised plans for PUC review and approval. Both subsections would allow the Commission or its designee to accept or reject the plan or revised plan. Representatives for EDCs and IRRC suggested that the words "or its designee" be deleted from the proposed regulation. PECO specifically commented that the Commission should also remove the language in proposed Section 57.198(b) and (c) permitting the Commission's "designee" to accept or reject EDC I&M plans.

There is concern that the proposed regulation does not describe or define the designee. Another concern is that EDCs are not given the ability to appeal or challenge decisions made by the designee. The regulation should be amended to define the designee and specify how EDCs may appeal the designee's decision, or the term should be deleted from the final-form regulation. We have removed the phrase "the designee" and have replaced it with "the Director of CEEP" such as to be specific as to which Bureau is being given the authority vested in the Commission to make such a staff determination. Language regarding how EDCs may appeal any determination by CEEP is in subsection (k).

IRRC commented that the PUC should set forth the update process, procedures and criteria the Commission will use in determining the need for information and plan updates, and for notifying the affected EDC. Since we are eliminating the update process, this is no longer necessary.

Subsection (c) -- Revised plans from EDCs

IRRC's comments state that proposed subsection (c) allows an EDC to revise its plan and submit it to the Commission for review. Like subsection (b), this subsection states that the Commission will have 90 days to review and accept or reject the revisions to the plan. Unlike subsection (b), however, subsection (c) contains no provision stating that the Commission will notify the EDC as to why it rejected the plan nor a provision stating that the revised plan is "deemed accepted" absent any action by the PUC within 90 days. IRRC's comments state that these provisions should also appear in subsection (c) in the final-form regulation.

A new subsection (j) has been added to address these concerns. CEEP will be obligated to notify the EDC, in writing, of any deficiencies in the plan; the EDC will have the opportunity to file either a revised plan or an explanation as to why the plan is not deficient. Absent action by the Commission within 90 days, the revised plan is deemed to be accepted by the Commission.

Subsection 57.198(b) and (c)

PECO commented regarding subsection (b) that the Commission should remove the language permitting the Commission's designee to accept or reject the EDC's plan because it does not clearly describe the official or entity designee that will have the authority to approve or reject the plan. The regulation is too vague and could include an Administrative Law Judge or staff person. PECO is concerned it won't be able to challenge the decision and bring the issue before the entire Commission.

IRRC commented that Subsection 57.198(b) and (c) set forth detailed procedures and time periods for PUC review and approval of plans and revised plans. If the PUC intends to retain the ability to request that EDCs update previously-approved plans, then a new and separate subsection clarifying this process should be added to the final-form regulation. It should set forth the process, procedures and criteria that the Commission will use in determining the need for information and plan updates, and for notifying the affected EDC. It should also include provisions similar to those in Subsections (b) and (c) for Commission review and approval of plan updates.

Upon consideration of these comments, we will change the language to specify the Director of CEEP will have the authority to accept or reject the EDCs' plans. The Director's decision would constitute a staff determination that could be appealed to the Commission under 52 Pa.Code §5.44. Staff action, under authority delegated by the Commission, will be deemed to be the final action by the Commission unless appealed to the Commission within 20 days after service of action. Petitions for appeal from the Director's action will be addressed by the Commission at Public Meeting. 52 Pa. Code §5.44(j). If the Commission itself makes the determination, then the EDC may file a petition for reconsideration pursuant to 52 Pa. Code § 5.572 or, alternatively, file an appeal directly to Commonwealth Court. This will be addressed in subsection (k) of Annex A.

We are also are adding language to subsection (l) which states that an EDC may request approval from the Commission for revising an approved plan. An EDC shall submit to the Commission, as an addendum to its quarterly reliability report, prospective and past revisions to its plan and a discussion of the reasons for the revisions. Within 90 days, the Commission or the Director of CEEP will accept or reject the revisions to the plan.

Subsection (d) Recordkeeping

This subsection requires an EDC "maintain records of its inspection and maintenance activities sufficient to demonstrate compliance with" the timeframes for I&M programs set forth in subsection (e). IRRC commented that the Commission needs to provide examples of the types of records that would be "sufficient." Would this include date-stamped records signed by EDC staff that performed the tasks?

To address this concern, additional language has been added to provide examples. Receipts from independent contractors showing when and what type of inspection, maintenance, replacement and/or repair work was done is also sufficient.

Subsection (e) minimum timeframes for I&M activities

This subsection sets specific statewide minimum schedules for several different types of I&M activities including vegetation management, and inspection of poles, overhead lines and substations. IRRC comments that the EDCs contend there is no basis for setting specific minimum requirements and that they are not cost-effective.

IRRC also mentions that I&M inspection schedules or timeframes for different EDCs may depend on the regions where their systems are located, the different types of plants and geography in those regions, fluctuating weather patterns, variations in equipment or infrastructure, and other factors. IRRC commented that the Commission needs to respond to the EDCs' concerns about mandated annual foot patrol inspections of distribution lines, and the need for foot patrols when the lines run parallel to roadways and could be inspected from vehicles. The Commission agrees that foot patrols are not necessary especially since vehicle patrol carrying testing equipment is available for proper testing. We will replace the word "foot" with the word "ground." This is addressed in Annex A.

The EAP commented that by the nature of their function, electric transmission and distribution systems have thousands of parts of varying degrees of complexity and importance dispersed over a large geographic area. Maintaining systems in a cost effective manner requires maintenance programs that take into account the characteristics of component parts, the environment in which they operate, and the electrical and mechanical stresses they experience. EDCs need flexibility to invest in technological improvements. Mandated labor-intensive programs with high costs impairs the EDC's flexibility to invest in improvements that would produce greater benefits to the consumer. For example, advancements in sensor technology has brought about smaller, more powerful sensors available at increasingly lower prices.

The rapid pace of advancement in communications has also made it possible to monitor sensors remotely and accumulate technical information at central points such as main office buildings, service centers, substations, and on poles and towers. Also, technology has improved with computer applications that should improve reliability because new systems allow EDCs to identify more specific areas to address and then sort out the best course of action.

Allegheny Power commented that approximately 97% of its customer interruptions were caused by distribution faults of which 70% directly resulted from external events unaided by frequent inspections, such as off-rights-of-way fallen trees, vehicles hitting poles, etc. The remaining 30% of outages include indirect effects of severe weather and other causes targeted by AP's current maintenance programs. Recloser failures made approximately 1% of total customer interruptions, overhead transformer failures were linked to approximately 1 to 1.5% of customer interruptions, poles were related to .8% of customer interruptions and underground transformers caused .25% of customer interruptions.

Allegheny Power claims the Proposed Rulemaking would increase Allegheny Power's costs by $8.4 million and $2 million in start up costs. The AFL-CIO and OCA proposals add an additional $4.5 million and $5.5 million, respectively. Allegheny Power recommends allowing NERC standards and PJM to ensure continued high reliability of transmission grids without increasing costs. Regarding substations, AP recommends eliminating the time-based I&M requirements to allow advanced analysis and technologies to be implemented. AP further recommends allowing EDCs to submit individualized cost and operationally effective I & M plans to target resources to areas in need of reliability improvements, and allow for changes to the plans as technologies are implemented.

In response to these concerns and to IRRC's concerns regarding rigid minimum standards for I&M activities, the Commission has adopted a flexible approach that will permit an individual EDC to deviate from the I&M standards set forth in these regulations provided the deviations can be justified by the EDC's unique circumstances or a cost/benefit analysis. This will allow implementation of these regulations to take into consideration the various differences among EDCs regarding geography, age of facilities, technologies employed and other factors that bear on the reasonable and prudent intervals that should be used for the proper inspection and maintenance of their facilities.

Lastly, for critical maintenance issues, items that threaten short-term reliability of facilities, AP is comfortable with a 30-day standard. For non-critical issues, the most effective method is to schedule repair/replacement in the following budget cycle. We agree with AP and include 30-day repair requirements to Section 57.198(n)(3) and (5).

(e) An EDC shall maintain the following minimum inspection and maintenance plan intervals.

As stated earlier, rather than rigid minimum I&M standards, the Commission will establish standard intervals, based on current industry practices. If however, a given EDC believes that a deviation is appropriate, it may seek to justify an alternative approach. The following are charts compiled by the Commission from data offered to the Commission by the EDCs which compare the EDC's I&M

standards from 1990, 1995, 2000, to current and the claimed incremental cost of meeting the proposed standards.

The charts are followed by comments and a discussion regarding the specific (sometimes bolded) proposed language above the charts.

Proposed: 52 Pa. Code § 57.198(e)(1): *Vegetation management.* The Statewide minimum inspection and treatment cycles for vegetation management are 4 years for distribution facilities and 5 years for transmission facilities.

Company	1990	1995	2000	Current	Incremental Cost
Allegheny	No set cycle for distribution or transmission.	Distribution trim cycles in urban areas from 2 to 4 years and from 4 to 8 years in rural areas. No set cycle for transmission.	Distribution trim cycles in urban areas from 2 to 4 years and from 4 to 8 years in rural areas. No set cycle for transmission.	Four-year cycle for distribution circuits. No set cycle for transmission.	$4,100,000
Duquesne	No established cycles.	No established cycles.	Distribution cycle > 6 years; transmission cycle > 7 years.	Actual average distribution cycle=5.63 years; actual average transmission cycle= 7.04 years.	$2,750,000
Met-Ed	Not readily available.	Not readily available.	Distribution cycle of 4 years; transmission cycle of 6 years. (2001)	Distribution cycle of 4 years; transmission cycle of 5 years.	NA
Penelec	Not readily available.	Not readily available.	Distribution cycle of 4 years; transmission cycle of 6 years. (2001)	Distribution cycle of 4 years; transmission cycle of 5 years.	NA
Penn Power	Not readily available.	Not readily available.	Distribution cycle of 4 years; transmission cycle of 6 years. (2001)	Distribution cycle of 4 years; transmission cycle of 5 years.	NA
PECO	Distribution practices not consistently applied; 5-year transmission cycle in 1992.	Distribution cycle of 4 years; transmission cycle of 5 years.	Distribution cycle of 5 years; transmission cycle of 5 years.	Distribution cycle of 5 years; transmission cycle of 5 years.	$5,000,000
PPL	No company-wide standard for distribution and transmission.	Changes in policy for transmission unknown; no company-wide standard for distribution.	NA	Distribution cycles 8 years rural and 5 years urban; transmission inspected every 3 to 5 years.	$14,300,000

UGI	Circuits are prioritized after inspection.	Circuits are prioritized after inspection.	Circuits are prioritized after inspection.	Circuits are prioritized after inspection.	$2,000,000 increase in operating expenses for all categories.
Citizens'	As deemed necessary.	As deemed necessary.	As deemed necessary.	As deemed necessary.	$20,000
Wellsboro	NA	12 years.	8 years.	8 years.	$195,000
Pike County	Distribution – 3 years.	Distribution – 3 years.	Distribution – 3 years.	Distribution – 3 years.	NA

Regarding distribution facilities, PECO has I&M programs with varying length and it wants to retain this flexibility. Shifting to a 4-year cycle for distribution lines, will cost an additional $4.5 to $5 million per year with no real increase in reliability associated with that increased cost. PECO cites to Dr. Googenmoos who reviewed the National Grid System in the Northeast U.S. Dr. Googenmoos stated that a proposal to standardize the grid's vegetation management to standard right-of-way widths constitutes an inefficient use of resources, costing 30-70% more than using site-specific prescriptions.

PECO commented that it currently employs a 5-year vegetation inspection and treatment plan for its transmission facilities based on its judgment, experience and the vegetation conditions it has observed. However, PECO submits that with regard to transmission facilities, a reasonable and appropriate approach would be for the Commission to monitor the ongoing development of transmission standards by FERC and NERC and to decline to adopt mandatory standards at this time. Recently, FERC issued a Notice of Proposed Rulemaking proposing to approve 83 of 107 reliability standards developed by NERC. Some of the regulations specifically address transmission line inspections.

PECO further commented that the Commission should allow utilities the ability to implement condition-based vegetation management programs that are not constrained by the cost inefficiencies of standardized cycles. PECO suggests the following language,

> "Vegetation management. As part of the plan required by Section 57.198(b), an EDC shall submit a condition-based plan for vegetation management for its distribution system facilities.

FirstEnergy practices a four-year tree trimming cycle on its distribution lines and a 5 year cycle on its transmission lines. FirstEnergy believes its cycle standard is reasonable. FirstEnergy requests Commission regulations that supersede local city, borough and other municipal ordinances that may attempt to limit tree trimming, removal of vegetation, the use of herbicides or that require stump removal, all of which are impediments to completing required and essential vegetation management in a cost effective and timely manner. Additionally, intrastate agency cooperation between the PUC, Game Commission, Department of Environmental Protection and Department of Conservation and Natural Resources would be helpful to the EDCs. Generally, FirstEnergy supports the EAP's comments which advocate eliminating a minimum vegetation standard altogether and keeping a requirement that vegetation management be addressed in the plans.

Duquesne Light commented there should not be rigid minimum intervals between vegetation maintenance periods. Pennsylvania has four distinct plant hardiness zones defined by the US Department of Agriculture. Because of these distinct zones, different areas of the state have different native trees which grow at different rates. Thus, varying maintenance requirements should be employed. Also, some utilities have different right-of-way maintenance widths and this influences the necessary maintenance intervals. Territories with wider right-of-way widths do not need to maintain the vegetation on the edges through pruning as frequently as those with narrower widths. Urban rights-of-way, usually within municipal rights of way, are generally narrower than those in rural areas where private property owners have granted rights. For these reasons, Pennsylvania should adopt an average cycle instead of a minimum cycle.

The Commission is attempting to balance the need for stricter vegetation management cycles for the EDCs that have had difficulty in the past meeting their reliability standards even with the stricter internal vegetation management standards, as opposed to other EDCs that have longer internal vegetation management standards, yet are more compliant in staying within their reliability standards. For example, the FirstEnergy companies have in the past violated their reliability standards, yet those companies now have 4 and 5 year tree-trimming cycles. FirstEnergy has recently been improving in its ability to stay within its reliability standards. PPL is traditionally a good performer, usually falling within its reliability standards each quarter, yet it has the longer tree-trimming interval of 8 years for distribution lines in rural areas. PPL was able to maintain its reliability benchmark between 2001 and 2005 using a five year urban and an eight year rural trim cycle. Although PPL admits shorter cycles will improve reliability, ultimately, it reaches some point of diminishing return. (January 22, 2007 Technical Conference Transcript. pp. 63-64).

Further, other states are not as strict with a minimum 4 and 5 year tree trimming interval standard. Texas has no requirements for tree-trimming, vegetation management or right-of-way clearance, but rather is guided by the provisions of the American National Standards Institute, Inc., the National Electrical Safety Code and other national standards. Ohio has in a limited fashion asked the utilities to set their vegetation goals, and New York reviews plans for transmission-specific and EDC-specific clearance requirements and reviews the plan. Massachusetts requires tree-trimming by utilities, and then has them report the results. For these reasons, and because the incremental cost increases seem to be high if we were to stay with the 4 and 5 year vegetation management standards, we will amend the rulemaking to substitute a standard of no longer than an 8-year cycle for distribution lines and will eliminate the transmission line requirement altogether at this point.

AFL-CIO commented Section 57.198(e)(1) should be revised to read:

> (1)Vegetation management. The statewide minimum inspection and treatment cycles for vegetation management are 4 years for distribution facilities and 5 years for transmission facilities. In addition if a circuit experiences five or more trips during a 12-month period, it shall be scheduled for an immediate vegetation inspection. Finally, utilities are encouraged to increase the frequency of their vegetation inspection cycles if an area experiences a wetter than normal growing season.

The added language reflects the fact that vegetation management programs must be dynamically managed. An EDC should not be able to simply establish a cycle and claim that it has acted reasonably. Vegetation plans must be adapted to growing conditions and an EDC must actively respond if a circuit experiences vegetation-related problems. While we generally agree that EDCs should be encouraged to increase their frequencies of vegetation inspection cycles during wetter than normal growing seasons, an "encouragement" statement doesn't belong in a regulation. Regulations should be unambiguous rules which are objective and easy to enforce, not vague and ambiguous.

Citizens' claims it performs a trimming needs assessment on its entire system each year, and targets a four-year trimming cycle; however, some locations are trimmed more frequently and some less frequently depending on the tree species, weather, line construction type and other factors. Wellsboro is not on a four-year cycle and projects that a mandatory four-year cycle will result in a fifty percent increase in its present right of way program budget. Neither Citizens' nor Wellsboro project an appreciable enhancement of service reliability as a result of 4-year tree trimming cycle standards.

The OCA commented that the 4 and 5 year standards are the current cycle standards for the FirstEnergy companies. A cost/benefit analysis must look at the long-term and must take into account unquantifiable benefits of safe and reliable service. To the extent that the range of 4-5 years is unduly burdensome for the EDC, the EDC can seek a waiver from the Commission through the appropriate procedures.

Disposition

Upon consideration of these comments, we will adopt language similar to the language proposed by PECO regarding a "condition-based plan" for vegetation management. However, based on our review of industry practices statewide and reliability results, we will also establish an interval standard of between 4-8 years for vegetation management on distribution lines. If an EDC believes that an alternative interval is appropriate, it may seek to justify that deviation by its unique circumstances or a cost/benefit analysis when it submits its plan.

In addition, the Commission will monitor what the Federal Energy Regulatory Commission is doing regarding the promulgation of federal regulations regarding vegetation management around transmission lines. We will coordinate with the Department of Environmental Protection, Department of Conservation and Natural Resources, and Game Commission regarding these issues.

Proposed: 52 Pa. Code § 57.198(e)(2): *Pole inspections*. Distribution poles shall be visually inspected every 10 years

Company	1990	1995	2000	Current	Incremental Cost
Allegheny	10 years.	10 years.	12 years.	12 years.	$700,000
Duquesne	No formal pole testing program.	Pole testing equipment acquired.	Pole testing program established; implemented on 12-15 year cycle.	Poles tested every 12-15 years; Infrared inspection every 5 years.	NA
Met-Ed	Not available.	Not available.	13 years.	13 years.	NA
Penelec	Not available.	Not available.	13 years.	13 years.	NA
Penn Power	10 years.	10 years.	As required.	As required.	NA
PECO	Variable divisional programs with 9-year target.	Variable divisional programs with 9-year target.	10 years.	Poles inspected every 10 years after 12th year.	NA
PPL	Initial inspection at 25 years; subsequent inspections from 1 to 9 years.	Initial inspection at 25 years; subsequent inspections from 1 to 9 years.	NA	Initial inspection at 25 years; subsequent inspections from 1 to 9 years.	One-time cost of $3,000,000
UGI	10 years.	10 years.	10 years.	10 years.	See 'UGI' above.
Citizens'	No inspections performed.	No inspections performed prior to 1998.	10 years.	10 years.	NA
Wellsboro	NA	12 years.	10 years.	10 years.	NA
Pike County	None.	None.	None.	None.	$25,000

The AFL-CIO proposes Section 57. 198(e)(2) should be revised to read:

(2) Pole inspections. Distribution poles shall be ~~visually~~ inspected every 10 years. <u>Pole inspections shall include drill tests at and below ground level, a shell test, visual inspection for holes or evidence of insect infestation, a visual inspection for evidence of unauthorized backfilling or excavation near the pole, visual inspection for signs of lightning strikes, and a load calculation. If a pole exhibits 67% or less of the strength of a new pole of comparable size, then it shall be replaced within 60 days. If a pole fails the groundline (or butt) inspection, shows dangerous levels of rot or infestation, or otherwise exhibits dangerous conditions or conditions that affect the integrity of the circuit, it shall be replaced as soon as possible, but no later than 30 days.</u>

AFL-CIO argues a visual inspection is insufficient to determine the integrity of the pole especially if 10 years lapse between inspections. Second, the regulation should set specific standards and deadlines for replacing poles that are seriously deficient or dangerous. OCA also commented that more specifications should be added to this section and that the detailed inspection every 10 years should include drill tests at and below ground level, a shell test, a load calculation, visual inspection for holes, evidence of insect infestation, evidence of unauthorized backfilling or excavation, lightening strikes and other problems. Poles with major deficiencies should be replaced within 60 days according to the OCA.

Duquesne Light commented that it can agree to visually inspect poles every ten years. PECO also commented that it does not oppose this inspection standard. The EAP argues increased pole inspections do not increase reliability because there is no causal relationship between increased frequency of pole inspections and reliability and customer service outages due to pole failures are extremely rare. The EAP states that the proposed ten-year cycle for pole inspection will increase the cost of electricity yet will have no impact on electric service reliability. The EDCs and their customers would experience $4.4 million of increased costs annually if the proposed 10-year inspection requirement is adopted. I&M cycle times are EDC and region specific and also vary by the type of pole and initial preservation treatment. Therefore, the EAP argues, the EDCs should be permitted to develop their own cycles for inspection of utility poles.

West Virginia has rules governing pole inspection. However, inspections are to be done with reasonable frequency. Kentucky requires a utility to construct and maintain its plants and facilities in accordance with good accepted engineering practices. The Kentucky Commission also adopted national standards including NESC ANSI-C-2, National Electric Code ANSI-NFPA-70, American National Standard Code for Electricity Metering ANSI-C-12-1, USA Standard Requirements for Instrument Transformers ANSI-Standard C.57.13 National Electrical Code. The

EAP suggests following the lead of West Virginia and Kentucky if we want to mandate pole inspections.

PPL's' General Manager- Transmission/Distribution, David E. Schleicher, P.E., testified that new Southern Yellow Pine (SYP) creosoted utility poles do not need as frequent tests as other poles like Penta and CCA initially. He stated the SYP creosoted pole needed an initial test at 25 years, and other poles needed testing initially every 10 years, then subsequently 1-9 years afterwards based upon the results of the prior year's testing. (January 22, 2007 Technical Conference Transcript, p. 60). The Commission agrees that the inspection should be more than a visual one, and we will incorporate some OCA's and the AFL-CIO's proposed language, but given PPL's testimony and EAP's comments, we will lengthen the general standard for wooden poles to be a range from 10-12 years.

Disposition

Upon consideration of these comments, we will amend the 10 years interval standard to allow for the creosoted pole to be inspected initially at 25 years to account for the new poles that are being installed by PPL and which do not need inspection for the first 25 years. We will add in language such that distribution poles shall be inspected at least as often as every 10-12 years except for the new SYP creosoted utility poles which shall be initially inspected within 25 years, then within 12 years annually thereafter.

We will also include language that pole inspections shall include drill tests at and below ground level, a shell test, visual inspection for holes or evidence of insect infestation, a visual inspection for evidence of unauthorized backfilling or excavation near the pole, visual inspection for signs of lightening strikes and a load calculation. If the pole fails the groundline inspection, shows dangerous conditions or conditions affecting the integrity of the circuit, it shall be replaced within thirty days of the date of inspection.

Proposed: 52 Pa. Code § 57.198(e)(3): *Overhead line inspections*. **Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years.** Distribution lines shall be inspected by foot patrol a minimum of once per year. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. Aboveground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle. Reclosers shall be inspected and tested at least once per year.

Company	1990	1995	2000	Current	Incremental Cost
Allegheny	Aerial patrols twice-year on 345 kV to 500 kV; annually for all other voltage levels. All patrols performed aerially.	Aerial patrols twice-year on 345 kV to 500 kV; annually for all other voltage levels. All patrols performed aerially.	Aerial patrols for all transmission voltages minimum of once per year; comprehensive patrol for 345-500 kV every 5 years and for 100-230 kV every 10 years.	Aerial patrols for all transmission voltages minimum of once per year; comprehensive patrol for 345-500 kV every 5 years and for 100-230 kV every 10 years.	$1,450,000
Duquesne	No VM aerial or foot patrols.	No VM aerial patrols; no thorough transmission line inspections for VM-related issues.	No VM aerial patrols; VM inspections > 7 years.	Lines > 200 kV aerially inspected 2 times per year; lines 200 kV and below aerially patrolled once a year.	$600,000
Met-Ed	Not available.	Not available.	Annual.	Annual.	$360,000 for the 3 FE companies
Penelec	Not available.	Not available.	Annual.	Annual.	See above.
Penn Power	Every 4 months.	Every 6 months.	Every 6 months.	Every 6 months.	See above.
PECO	Aerial inspections twice a year; foot inspections every 3 years.	Aerial inspections twice a year; foot inspections every 3 years.	Aerial inspections twice a year; foot inspections every 3 years.	Aerial inspections once a year; annual ground patrol for areas not accessible to helicopter.	NA
PPL	Uncertain.	Uncertain.	NA	Annual "quick fly-over annually; aerial inspections every 4 years; ground inspections every 4 years.	$12,000,000
UGI	Annual.	Annual.	Annual.	Annual.	See 'UGI' above.
Citizens'	No transmission.	No transmission.	No transmission.	No transmission.	NA
Wellsboro	No transmission.	No transmission.	No transmission.	No transmission.	NA
Pike County	No transmission.	No transmission.	No transmission.	No transmission.	NA

AFL-CIO commented Section 57.198(e)(3) should state:

(3) Overhead line inspections.

(i) Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery.

(ii) Distribution lines shall be inspected by foot patrol a minimum of once per year. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery.

(iii) Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. A visual inspection shall include checking for rust, dents or other evidence of contact, leaking oil, broken insulators, and any other conditions that may affect operation of the transformer,

(iv) Above-ground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle. An inspection shall include, as appropriate, checking for rust, dents or other evidence of contact, leaking oil, installation of fences or shrubbery that could affect access to and operation of the transformer, and unauthorized excavation or changes in grade near the transformer. In addition, the load on each transformer shall be calculated at least once every two years.

(v) Reclosers in the distribution system shall be inspected and tested at least once per year.

(vi) The integrity of transmission towers shall be inspected and tested at least once every 25 years.

The AFL-CIO argues these above underlined changes are necessary to improve the reliability of the regulation by adding subparagraphs for each type of facility and clarification.

OCA had similar comments to AFL-CIOs regarding this section. OCA believes transmission lines and all attached equipment should be inspected aerially twice per year in the spring and fall and if problems are found that affect the integrity of the circuits, they should be repaired or replaced within 30 days from discovery. OCA requests distribution lines undergo a detailed inspection every five years including infrared scanning. OCA wants the load on transformers to be calculated at least once every two years and if problems are found, then the equipment should be repaired or replaced within 30 days from discovery. OCA agrees reclosers should be tested at least once per year, but OCA recommends adding the requirement that if problems are found that affect the integrity of the equipment, they should be repaired or replaced within 30 days from discovery. OCA adds requirement (vi) which states as follows:

> (vi) Other critical Facilities shall be tested and inspected either annually or every two years. Switches shall be inspected and tested annually. Relays, sectionalizers, and vacuum switches shall be inspected and tested every two years. If problems are found that affect the integrity of the equipment, they shall be repaired or replaced within 30 days from discovery.

Comments of OCA, November 6, 2006.

Finally, OCA commented Section 57.198(e)(4) should state:

> (4) Substation inspections and repair. Substation equipment, structures and hardware shall be inspected monthly. An inspection that includes infrared scanning shall be conducted annually. Substation circuit breakers should undergo operational testing at least once per year, diagnostic testing at least once every four years, and comprehensive inspection and maintenance on a four-year cycle. Deficiencies identified should be repaired or addressed within 30 days if serving transmission lines and within 60 days if serving distribution lines.

PPL commented that overhead equipment failure caused the most outages in 2006. It argues the I&M standards should be customized for each EDC to account for its unique asset structure, service area, technological sophistication, and performance. It should also easily adapt over time to changing technology, work methods, costs and structures. PPL suggests EDCs should be divided into two groups, each submitting custom plans in alternate years. The Commission would review and identify changes if necessary. Any approved plan would set the standards for that particular EDC. The Commission would then enforce compliance with the approved plan as well as compliance with reliability standards. We do not see any need to split the EDCs into two groups. Staff can review the plans as they are submitted on October 1 of each year.

Senator Tomlinson commented that requiring two men to walk a transmission line, or aerial overviews of lines appears to be cost-prohibitive and unduly burdensome. Further, the Senator urged the Commission to consider revising its standards and mandated time cycles. To take the regulation from no mandated cycles to highly restrictive standards seemed to be too restrictive to the Senator.

Duquesne Light commented that aerial inspection of transmission lines on an annual basis is sufficient. If significant events occur such as major storms, aerial inspections may be performed more frequently than annually. Duquesne performs biannual aerial inspections on transmission lines greater than 200 kV and critical circuits, while transmission lines below 200 kV are aerially inspected once a year, and it is sufficient to locate and repair problems.

Duquesne Light further commented that the Commission should question whether it has full authority to regulate reliability standards for transmission. NERC and FERC have been very active with transmission reliability and Pennsylvania's standards for transmission reliability are inconsistent with FERC's proposed regulations. Further, newer transmission lines are less in need of annual inspections than older lines. A minimum standard does not account for this and unnecessary costs will be expended to annually inspect the new lines. PECO's 5-year plan for distribution lines falls within the Commission's new proposed guidelines of 4-8 years. We will decline to regulate inspection cycles on transmission lines at this time and will monitor FERC's Advanced Proposed Rulemaking regarding transmission lines.

PECO commented that the Commission should decline to adopt mandatory I&M regulations relating to transmission lines. PECO currently inspects its transmission lines by aerial patrol once a year, in the spring, and this is supplemented by a ground patrol by foot or vehicle in areas that cannot be inspected by air or that need follow-up. PECO believes that inspecting twice a year is unnecessary and would not increase the reliability of the transmission line system and instead would only result in a significant increase to its transmission inspection costs.

Disposition

Upon consideration of these comments, we will decline to promulgate a standard regarding transmission lines and will monitor FERC's rulemaking proceeding at this time. Although we believe we have jurisdiction to create inspection, maintenance, repair and replacement standards regarding transmission lines, FERC has a rulemaking underway addressing these issues. However, we would still like the EDCs to include their I&M plans with their tree-trimming cycles and other inspection and maintenance cycles detailed with regard to transmission lines just so that we may monitor I&M efforts in Pennsylvania.

Proposed: 52 Pa. Code § 57.198(e)(3): *Overhead line inspections*. Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years. **Distribution lines shall be inspected by foot patrol a minimum of once per year.** If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. Aboveground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle. Reclosers shall be inspected and tested at least once per year.

Company	1990	1995	2000	Current	Incremental Cost
Allegheny	Inspected every 10 years.	Inspected every 10 years.	Inspected every 12 years.	Inspected every 12 years.	$1,500,000
Duquesne	No formal inspection program.	No formal inspection program.	Infrared inspection on a 5-year cycle.	Infrared inspection on a 5-year cycle.	$750,000 + initial investment of $300,000
Met-Ed	Not available.	Not available.	Not available.	Not available.	$1,950,000 for the 3 FE companies
Penelec	Not available.	Not available.	Not available.	Not available.	See above.
Penn Power	Not available.	Not available.	Not available.	Not available.	See above.
PECO	Variable divisional programs with 1 year target.	Variable divisional programs with 1 year target.	Drivable portion patrolled every year.	Ground patrol inspection using thermography every 2 years; areas not accessible by vehicle inspected by foot patrol.	NA
PPL	As required.	As required.	NA	No fixed interval; based on CPI.	Included in transmission line cost.
UGI	NA	NA	NA	NA	See 'UGI' above.
Citizens'	Annually.	Annually.	Annually.	Annually.	NA
Wellsboro	NA	5 years.	5 years.	3 years.	$88,000
Pike County	No foot patrol; infrared inspection annually for 3-phase and 3 years for other lines.	No foot patrol; infrared inspection annually for 3-phase and 3 years for other lines.	No foot patrol; infrared inspection annually for 3-phase and 3 years for other lines.	No foot patrol; infrared inspection annually for 3-phase and 3 years for other lines.	$55,000

Overhead line inspections distribution – foot patrol annually and transmission aerially twice per year and foot patrol every two years.

The EAP claims inspection costs would increase by $12 million annually, due to the necessity of more frequent inspections. The distribution line inspection under the proposed regulation would cost $4.6 million above present practices, and the above chart roughly supports that assertion.

The EAP claims that the current inspection and maintenance programs on overhead distribution lines utilized by Pennsylvania EDCs work well to both find and fix the problems. They focus on identifying deterioration of facilities, encroachment on the lines by property owners and vegetation, and finding damage to equipment that has not resulted in a service outage. Most equipment or material-related failures are caused by internal deterioration that is not readily determined by visual means. Many equipment failures are caused by lightening strikes, high winds, or other severe weather events that cause flashovers or through-faults at the time of the event. These failures will not be decreased by increasing frequency of visual inspections. Therefore, the EDCs wish to retain their individual inspection cycles for distribution lines.

Duquesne Light commented that annual foot patrols are extremely time consuming, expensive and labor intensive. Duquesne has over 7,000 miles of lines traversing varying terrain, and that amount is very small in comparison with other utilities in the state. Annual foot patrols are not relevant to Duquesne. The PUC should encourage the use of intelligent automated distribution components that have self-diagnostic capabilities and can be monitored remotely. Duquesne agrees that 30 days from discovery is a reasonable length of time within which to repair a known problem found during an inspection that can affect the integrity of the system subject to certain conditions, i.e. scheduling line outages for repair work must be coordinated with PJM, etc.

PECO commented that the Commission should not adopt the distribution line inspection requirement because PECO already maintains and inspects its distribution system in compliance with all requirements of the National Electric Safety Code and the Commission should defer to the Code. PECO uses a ground patrol every two years that includes visual and thermographic inspection of its system. The thermographic computer equipment determines where hot spots are on the distribution lines, transformers and electrical connections. PECO believes that more frequent measurements would not measurably improve the reliability of the systems.

Disposition

Upon consideration of these comments, we are persuaded to change the annual standard to a 1-2 year requirement because most of the EDCs do not inspect annually, and some only use thermography, instead of foot patrol. If critical maintenance problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery.

An inspection shall include checking for broken insulators, conditions that may affect operation of the overhead transformer, and other conditions that may affect operation of the overhead distribution line.

Proposed: 52 Pa. Code § 57.198(e)(3): *Overhead line inspections*. Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years. Distribution lines shall be inspected by foot patrol a minimum of once per year. **If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery.** Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. Aboveground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle. Reclosers shall be inspected and tested at least once per year. Since the bolded portion above seems to cause no immediate problems, it will remain in the regulation.

Company	1990	1995	2000	Current	Incremental Cost
Allegheny	Hazardous conditions repaired as soon as possible; problems without near-term consequences	Hazardous conditions repaired as soon as possible; problems without near-term consequences	Hazardous conditions repaired as soon as possible; problems without near-term consequences	Hazardous conditions repaired as soon as possible; problems without near-term consequences	NA

	scheduled within following budget cycle.	scheduled within following budget cycle.	scheduled within following budget cycle.	scheduled within following budget cycle.	
Duquesne	Serious problems were corrected when funding and resources were available.	Serious problems were corrected when funding and resources were available.	Serious problems generally corrected within 6 months; no standard for timely action.	Serious problems corrected within 30 days; no standard for timely action on lower priority issues.	NA
Met-Ed	No response.	No response.	No response.	No response.	Unknown.
Penelec	No response.	No response.	No response.	No response.	Unknown.
Penn Power	No response.	No response.	No response.	No response.	Unknown.
PECO	No response.	No response.	No response.	No response.	NA
PPL	Critical problems immediately addressed; others combined with other work; transmission problem schedule based on severity.	Critical problems immediately addressed; others combined with other work; transmission problem schedule based on severity.	Critical problems immediately addressed; others combined with other work; transmission problem schedule based on severity.	Critical problems immediately addressed; others combined with other work; transmission problem schedule based on severity.	NA
UGI	No response.	No response.	No response.	No response.	See 'UGI" above.
Citizens'	No response.	No response.	No response.	No response.	NA
Wellsboro	No response.	No response.	No response.	No response.	NA
Pike County	No standard.	No standard.	No standard.	No standard.	NA

EAP claims that placing a thirty day limitation for repair will not improve reliability because it will not accelerate the repair of urgent problems; conversely, it will increase cost and decrease resource flexibility for work crews by placing artificially short time schedules on non-critical repairs. The EDCs should retain the ability to determine the urgency of repair and to schedule resources accordingly.

Disposition

If critical maintenance problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. Therefore, the Commission will adopt some of the AFL-CIO's language and incorporate it into subsection (n)(5) because without some repair deadlines, the regulation has less meaning.

Proposed: 52 Pa. Code § 57.198(e)(3): *Overhead line inspections*. Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years. Distribution lines shall be inspected by foot patrol a minimum of once per year. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. **Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection.** Aboveground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle. Reclosers shall be inspected and tested at least once per year

Company	1990	1995	2000	Current	Incremental Cost
Allegheny	Inspected in conjunction with circuit inspection.	Inspected in conjunction with circuit inspection.	Inspected in conjunction with circuit inspection.	Inspected in conjunction with circuit inspection.	Additional cost included in foot patrol.
Duquesne	No formal inspection program.	No formal inspection program.	Infrared inspection on a 5-year cycle.	Infrared inspection on a 5-year cycle.	NA
Met-Ed	Every 4 years.	Every 4 years.	Every 6 years.	Every 6 years.	Included in line inspection.
Penelec	Every 4 years.	Every 4 years.	Every 6 years.	Every 6 years.	Included in line inspection.
Penn Power	Every 4 years.	Every 4 years.	Every 6 years.	Every 6 years.	Included in line inspection.
PECO	Variable divisional programs with 1 year patrol target.	Variable divisional programs with 1 year patrol target.	Drivable portion patrolled every year.	Inspected as part of 2 year distribution line inspection.	NA
PPL	Uncertain.	Uncertain.	NA	No fixed interval.	NA
UGI	NA	NA	NA	NA	See 'UGI' above.
Citizens'	Annually.	Annually.	Annually.	Annually.	NA
Wellsboro	NA	5 years.	5 years.	5 years.	Included in line inspection.
Pike County	Annual infrared inspection for 3-phase; 3 years for other lines.	Annual infrared inspection for 3-phase; 3 years for other lines.	Annual infrared inspection for 3-phase; 3 years for other lines.	Annual infrared inspection for 3-phase; 3 years for other lines.	$15,000

Inspection of overhead distribution transformers annually

EAP opposes a uniform standard for the annual inspection of pole mounted distribution transformers. Increasing visual inspection of overhead distribution transformers will not increase customer service reliability according to the EAP. EDCs' current inspection programs uncover few transformer problems. Overhead transformer failures typically affect only a few customers.

EAP alleges that increasing the frequency of inspection will not produce significant additional reliability benefits but will greatly increase costs and divert resources that could be used for EDCs' maintenance programs that yield greater reliability benefits. Many transformer failures result from causes that occur right before the failure, such as lightening, or storm-related faults on secondary/service conductors. Annual visual inspections will not decrease the number of these events and will increase costs by approximately $2.9 million annually. Therefore, EAP argues the EDCs should be allowed to continue to inspect overhead transformers using their current schedule.

Disposition

The Commission is not entirely persuaded by EAP's argument. We believe it is a reasonable requirement that when the distribution lines are inspected every 1-2 years, that as part of that inspection, distribution pole transformers are also inspected. The incremental cost for this was already included in the line inspection estimates for most of the EDCs anyway. As we have decreased the minimum inspection standard from annually to biennially, the costs for the overhead transformer inspections diminish.

A visual inspection of distribution transformers shall include checking for rust, dents or other evidence of contact, leaking oil, and any other conditions that may affect operation of the transformer. This language as proposed by the AFL-CIO will be incorporated in Annex A under subsection (n)(6).

Proposed: 52 Pa. Code § 57.198(e)(3): *Overhead line inspections*. Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years. Distribution lines shall be inspected by foot patrol a minimum of once per year. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. **Aboveground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle.** Reclosers shall be inspected and tested at least once per year.

Company	1990	1995	2000	Current	Incremental Cost
Allegheny	Inspected every 6 years.	Inspected every 4 years.	Inspected every 5 years.	Inspected every 5 years.	$100,000
Duquesne	Network underground transformers inspected semi-annually.	Network underground transformers inspected semi-annually.	Network underground transformers inspected annually.	Network underground transformers inspected annually.	$450,000
Met-Ed	Every 4 years.	Every 4 years.	Every 6 years.	Every 6 years.	$1,200,000 for the 3 FE companies
Penelec	Every 4 years.	Every 4 years.	Every 6 years.	Every 6 years.	See above.
Penn Power	Every 4 years.	Every 4 years.	Every 6 years.	Every 6 years.	See above.
PECO	Inspected following report of unusual condition.	Inspected following report of unusual condition.	5-year inspection cycle.	5-year inspection cycle.	NA
PPL	Uncertain.	Uncertain.	NA	No fixed interval for pad-mounted; vaults inspected every 6 months.	NA
UGI	NA	NA	NA	NA	See 'UGI' above.
Citizens'	Annually.	Annually.	Annually.	Every 4 years.	$25,000
Wellsboro	NA	5 years.	5 years.	5 years.	$15,000
Pike County	None.	None.	None.	None.	$10,000

Inspection of pad-mounted or below-grade transformers every two years. The EAP opposes a standard for the inspection of pad-mounted and below-grade transformers every two years. Current inspection programs for this equipment are sufficient to maintain this equipment in a reliable fashion. Increasing the frequency of inspection of these devices will not significantly improve customer service reliability and will increase cost by approximately $4.0 million annually. EAP argues EDCs should retain the ability to establish inspection programs for pad-mounted and submersible equipment to optimize use of inspection resources and customer service reliability.

Duquesne Light commented that nothing can be determined by visually inspecting a transformer, other than an occasional oil leak. Almost all of Duquesne's transformer failures are the result of thermal overload, which cannot be detected by visual inspection. It is better to analyze transformer capacity when there is a change in service to customers, such as the addition of new load or during periods of high heat when there is more stress on the system. It is nearly impossible to inspect below-ground transformers according to Duquesne Light because they are submersible or in vaults and inspection problems surface regarding confined space rules and the availability of trained personnel.

PECO believes the Commission should not adopt the proposed regulation's two-year inspection requirement for pad-mount and underground transformers. PECO states that they have an approximate failure rate of once every 100 years. PECO currently inspects pad-mount transformers every 5 years and underground transformers every six years. These cycles are more than sufficient to maintain transformer reliability. PECO suggests amending the proposed regulations to state: Aboveground pad-mounted transformers and below-ground transformers shall be inspected on a cycle of 8 years or less.

Disposition

We recognize that a pad-mounted transformer and below-ground transformer are generally less likely to be struck by lightening and malfunction than a pole transformer. Therefore, we will adopt in part PECO's suggestion. The standard for inspecting a pad-mounted transformer will be a minimum interval of every 5 years, and the standard for inspecting a below-ground transformer will be a minimum interval of every 8 years or less.

Equipment failure is a major cause of outages, and the benefit to the customers in having these pad-mounted and underground transformers inspected every 5 or 8 years is of great value as we believe it will lead to fewer outages and less duration of average outages. If the EDC wants to exceed the standard, it my request so in writing with its plan and explain why that type of interval should be allowed and submit a cost/benefit analysis to support its claim. Otherwise, aboveground pad-mounted transformers and below-ground transformers shall be inspected on a 5-year and 8-year cycle respectively.

An inspection shall include checking for: 1) rust, dents or other evidence of contact; 2) leaking oil; 3) installation of fences or shrubbery that could affect access to and operation of the transformer; and 4) unauthorized excavation or changes in grade near the transformer.

Proposed: 52 Pa. Code § 57.198(e)(3): *Overhead line inspections*. Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years. Distribution lines shall be inspected by foot patrol a minimum of once per year. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. Aboveground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle. **Reclosers shall be inspected and tested at least once per year.**

Company	1990	1995	2000	Current	Incremental Cost
Allegheny	Inspected every 3 years.	Inspected every 3 years.	Inspected every 5 years.	Inspected every 5 years.	$2,000,000 + $2,000,000 startup
Duquesne	Condition-based maintenance on 23 kV Reclosers on 1-year cycle; single phase 4 kV reclosers not tested.	Condition-based maintenance on 23 kV Reclosers on 1-year cycle; single phase 4 kV reclosers not tested.	Condition-based maintenance on 23 kV reclosers on 1-year cycle; single phase 4 kV reclosers not tested.	23 kV reclosers w/o self-monitoring systems inspected on 1-year cycle; no planned maintenance for modern reclosers; single phase 4 kV reclosers not tested.	$85,000
Met-Ed	Oil reclosers – oil test on 5-year cycle; overhaul on 9-year cycle.	Oil reclosers – oil test on 5-year cycle; overhaul on 9-year cycle.	Oil reclosers – oil test on 5-year cycle; overhaul on 9-year cycle.	Oil reclosers – oil test on 5-year cycle; overhaul on 9-year cycle.	$1,600,000 for the 3 FE companies
Penelec	NA	NA	Visual and battery test inspection on 4 year cycle.	Visual and battery test inspection on 4 year cycle.	See above.
Penn Power	Annual field inspection and complete shop inspection performed based on number of fault operations.	Annual field inspection and complete shop inspection performed based on number of fault operations.	Annual field inspection and complete shop inspection performed based on number of fault operations.	Annual field inspection and complete shop inspection performed based on number of fault operations.	See above.

PECO	Variable divisional programs with 1 year target.	Variable divisional programs with 1 year target.	2-year inspection cycle.	Inspection cycles range from 1 to 4 years, depending on type.	NA
PPL	6-year replacement cycle.	8-year replacement cycle.	NA	10-year replacement cycle.	NA
UGI	5 years/100 operations.	5 years/100 operations.	5 years/100 operations.	5 years/100 operations.	See 'UGI' above.
Citizens'	Manufacturer's recommendations.	Manufacturer's recommendations.	Manufacturer's recommendations.	Manufacturer's recommendations.	$15,000
Wellsboro	NA	6 years.	6 years.	5 years.	$35,000 + $140,000 for purchase of add. OCRs.
Pike County	Visual inspection quarterly; tested semi-annually.	Visual inspection quarterly; tested semi-annually.	Visual inspection quarterly; tested semi-annually.	Visual inspection quarterly; tested semi-annually.	NA

Inspection and testing of reclosers once per year

EAP agrees with the need for individual programs for inspection and testing of reclosers, but it does not agree with the proposed regulation mandating this work be done on all reclosers on a one year cycle. EAP claims that improvements in technologies and communications are resulting in the development of intelligent reclosers that specifically do not require time-based inspections. Some EDCs are also adopting condition based maintenance practices for their equipment, that are based on operating cycles and other "wear and tear" independent of the time in-service.

The amount of wear that a recloser experiences is related to the frequency of operation and ambient weather conditions rather than to the duration of installation. A newly installed recloser will have a trip frequency based on the number of faults on the line that it protects, rather than on the length of time that the recloser is installed. During the course of a year, due to changes in severe weather and other external causes, this recloser may not trip at all, or it may trip several times. Reclosers that meet their manufacturer's recommended fault duty in one year are extremely rare. Initiating a one-year testing standard would cause EDCs to routinely spend resources inspecting and testing reclosers that are in new or nearly new condition. According to EAP, the additional cost of recloser inspection and testing to the EDC is estimated to be approximately $14.0 million annually.

Duquesne Light states that the 4 kV hydraulic reclosers cannot be inspected and tested without their complete removal from the distribution system and their transportation to the utility shop for inspection and testing. There is no portable test available to confirm function with the reclosers in place. This proposed annual testing would be very expensive. If the proposed recloser inspection and testing standard were to be adopted, Duquesne believes many utilities would use fuses instead of reclosers due to the cost of removal for inspection and testing. Fusing would decrease reliability and would be an unintended outcome.

Citizen's and Wellsboro question the need for standards regarding reclosers as well. Each company tailors its plan to the equipment and needs of the specific territory. Even for two EDCs of similar size, the maintenance practices differ due to other factors such as age and type of equipment, terrain, and weather variations. Further, because the number of reclosers operations that occur is small between testing intervals, some reclosers may not need retesting on an annual basis as per the manufacturer's specifications regarding testing and maintenance.

PECO does not support annual testing of all reclosers because they are not manufactured equally. There are different types and each has a different industry standard/best practices inspection and testing schedule. PECO tests oil-insulated reclosers every two years and solid-dielectric-insulated reclosers every four years consistent with the industry practice for these reclosers. To test all reclosers once per year would be a waste of resources, especially single phase reclosers, which are simple, self-contained devices mounted high on poles in the zone of the primary wires. Manufacturers do not recommend frequent testing of single-phase reclosers. PECO recommends amending the subsection as follows:

> ~~Reclosers shall be inspected and tested at least once per year.~~ Three-phase reclosers shall be inspected on a cycle of 8 years or less. Single-phase reclosers shall be inspected as part of the EDC's individual distribution line inspection plan.

Disposition

Upon consideration of these comments, we are persuaded by the EDC commenters to amend this section in the interest of not wasting resources. Three-phase reclosers shall be inspected on a cycle of 8 years or less. Single-phase reclosers shall be inspected as part of the EDC's individual distribution line inspection plan. This requirement will be incorporated under subsection (n)(7).

Proposed: 52 Pa. Code § 57.198(e)(4): *Substation inspections*. Substation equipment, structures and hardware shall be inspected monthly.

Company	1990	1995	2000	2005	Incremental Cost
Allegheny	Monthly for EHV substations; quarterly for others.	Monthly for EHV substations; quarterly for others.	Monthly for EHV substations; quarterly for others.	Monthly for EHV substations; quarterly for others.	$900,000
Duquesne	Monthly inspections.	Monthly inspections.	Monthly inspections.	Monthly inspections.	NA
Met-Ed	Monthly inspections.	Monthly inspections.	Monthly inspections.	Monthly inspections.	NA
Penelec	Monthly inspections.	Monthly inspections.	Monthly inspections.	Monthly inspections.	NA
Penn Power	Monthly inspections.	Monthly inspections.	Monthly inspections.	Monthly inspections.	NA
PECO	Monthly inspections.	Monthly inspections.	Monthly inspections.	Every 5 weeks.	NA
PPL	Critical – weekly; non-critical – monthly.	Critical – weekly; non-critical – quarterly.	NA	Critical – weekly; non-critical – monthly.	$2,200,000
UGI	230 kV – semi-monthly; 69 kV – semi-monthly.	230 kV – semi-monthly; 69 kV – monthly.	230 kV – semi-monthly; 69 kV – monthly.	230 kV – semi-monthly; 69 kV - monthly.	See 'UGI' above.
Citizens'	Monthly inspections.	Monthly inspections.	Monthly inspections.	Monthly inspections.	NA
Wellsboro	NA	Bi-monthly.	Monthly.	Monthly.	NA
Pike County	Monthly.	Monthly.	Monthly.	Monthly.	NA

Substation equipment, structures and hardware shall be inspected monthly.

The EAP disagrees with a requirement for monthly substation inspections and claims that this new requirement would add about $3.3 million annually in EDC operating cost on a statewide basis. Current inspection programs are claimed to be sufficient to provide reliable substation operation. EDCs have studied results of more frequent inspections and have found little benefit in inspecting stations more frequently. All EDCs have routine cycles for inspecting substation equipment. These inspections are more rigorous than a visual inspection. Very few customer outage incidents occur because of substation equipment failure that would have been detectable prior to their occurrence by a routine visual inspection.

However, Duquesne Light agrees and supports the requirement that substation equipment structures and hardware be inspected monthly because of its potential impact on reliability and safety, should be inspected monthly.

Allegheny Power claims its substation-related outages have very little impact on customer reliability, historically approximately 1 percent of all outages. Allegheny Power claims frequent inspections were not producing reliability benefits, and the proposed standard would cost an additional $900,000 each year. Allegheny claims the AFL-CIO and OCA proposals add additional annual costs of $3.9 million and $5.4 million, respectively and that their plans offer insignificant opportunity for increased customer reliability and deter the use of advanced tools that can reduce the need for inspection. Allegheny believes rigid repair standards and time frames will increase the costs or possibly decrease reliability.

AFL-CIO agrees with the EDCs that it is neither feasible nor required to test substation breakers on a monthly basis, but AFL-CIO requests the regulations establish a reasonable inspection, maintenance and testing cycle for these facilities.

PECO commented that it inspects its substation equipment every five weeks and that this is sufficient. Shortening the period to four weeks, while minor, would significantly increase PECO's inspection costs without any measurable increase in reliability. Accordingly PECO recommends it be amended as follows:

§57.198(e)(4) Substation inspections. Substation equipment, structures and hardware shall be inspected ~~monthly~~ on a cycle of five weeks or less.

AFL-CIO proposes 52 Pa. Code § 57.198(e)(4) should be revised to state:

> (4) Substation inspections. Substation equipment, structures and hardware shall be inspected monthly. <u>Substation circuit breakers shall undergo operational testing at least once per year, diagnostic testing at least once every four years and comprehensive inspection and maintenance on a four-year cycle.</u>

Disposition

Based on our consideration of the comments and current industry practices we will allow for a range of five weeks as the standard interval. Thus, we will adopt PECO's suggested language in Annex A, at n(8). Also, we note that PPL failed to explain why their alleged incremental cost would be $2.2 million when they state they do critical substation inspections weekly and non-critical monthly inspections already.

AFL-CIO's new proposal for other inspection requirements.

The AFL-CIO proposes a new Section 57.198(5) to state:

> <u>(5) Other inspection requirements.</u>
> <u>(i) Group-operated line switches shall be inspected and tested annually.</u>
> <u>(ii) Relays shall be inspected and tested every two years.</u>

(iii) Sectionalizers shall be inspected and tested every two years.

(iv) vacuum switches shall be inspected and tested every two years.

(v) underground vaults with larger connections (750 Mcm or larger) shall be visually inspected and thermo-vision tested for hot spots annually. In addition, vaults of any size that serve schools, hospitals, public buildings, or residences shall be visually inspected and cleaned once per year.

Each of these provisions was recommended by AFL-CIO in response to the Advance Notice of Proposed Rulemaking. The Commission did not include them in the NOPR and did not discuss reasons for their exclusion. AFL-CIO submits that these additional inspection, maintenance, and testing requirements are necessary to ensure the safety and reliability of electric service.

Disposition

Upon consideration of this proposal, we are not persuaded this level of detail is required at this time in order to ensure service reliability does not deteriorate. The EDCs can explain to this level of detail, but it is not required.

Automatic penalties

Finally, AFL-CIO requests automatic penalties when an EDC fails to repair or replace critical or dangerous facilities within a stated period of time. Failing to repair dangerous conditions or replace dangerous and defective equipment poses a danger to utility workers and the public. AFL-CIO recommends civil penalties of $1,000 per day for each day that the violation continues after the mandated repair interval, as authorized by 66 Pa.C.S. §3301. AFL-CIO recommends, therefore, the addition of a new subsection to section 57. 198 to state penalties for noncompliance are such that if an EDC fails to repair or replace defective poles, transmission circuits or distribution circuits within a certain time frame, the EDC shall be subject to automatic penalty of $1,000 per day for each day the violation continues.

Disposition

Upon consideration of this proposal, we decline to impose automatic fines and penalties for failure to comply with the final regulations because the Commission wants to retain flexibility in assessing fines for non-compliance, to consider the reasons for non-compliance, and to consider whether the EDC is also violating reliability standards and the number of customer complaints. There are factors beyond the control of the EDCs which influence an EDCs ability to have reliable service and meet its inspection, maintenance and repair intervals, such as off-right-of-way vegetation problems and weather-related outages and the Commission needs flexibility in determining whether an excuse is in good faith or not and whether the problem can be remedied by corrective action plans, before fines and penalties are pursued.

PPL's Pilot Program Suggestion

PPL's General Manager of Transmission/Distribution commented at the technical conference held on January 22, 2007, that if the Commission were to implement standards, they ought to be done on a pilot basis first in a controlled experiment to see if the standards do, in fact, improve reliability. PPL suggested targeting the worst performing circuit areas. PPL offered a graph depicting the effect of the proposed standards on effective management of the company in its comments. Figure 1, p. 8. PPL stated that the tradeoffs between alternatives, costs and results change over time, are driven by advancements in technology and work methods, and changes to the specific makeup and age distribution of an EDC's assets. At any given time, a cost/benefit analysis will produce different results at different EDCs due to differences in labor costs, design standards, equipment and material specifications, asset retirement and replacement schedules, asset upgrading programs, facility operating procedures, and inspection and maintenance programs.

Thus, PPL recommends the most effective way to proceed is for the Commission to establish individual inspection and maintenance standards for each EDC, which recognize the unique characteristics, performance and environment of each EDC and which can be adapted to changing technology, work methods, costs and system composition. Uniform labor-intensive standards will not necessarily lead to improvements in reliability and will likely result in substantial additional costs to the EDCs totaling approximately $75 million per year.

Disposition

PPL's pilot program suggestion is interesting but no other party recommended the same. The final-form regulations set forth today will allow for flexibility in reacting to technological advancements in inspection, maintenance, replacement and repair work, as well as encouraging better performance in uniquely different EDC service territories.

III. Conclusion

The Commission finds that the establishment of I&M standards for EDCs, as set forth in Annex A, is in the public interest because these standards are required by law, 66 Pa. C.S. § 2802(20) and because these standards will enhance the reliability of the electric service provided to Pennsylvania ratepayers. In addition, we have given consideration to the industry's claim that rigid I&M standards may not be appropriate for all EDCs by allowing individual EDCs to justify, by unique circumstances or a cost/benefit analysis, the use of an alternative approach to a given I&M standard. Annex A reflects, through its red-lined markings, the cumulative changes made to Annex A of this Commission's Proposed Rulemaking Order entered on April 20, 2006.

Accordingly, under authority at Section 501 of the Public Utility Code, 66 Pa.C.S. §501, and Sections 201, *et seq.,* of the Commonwealth Documents Law, 45 P.S. §§1201, *et seq.,* 66 Pa.C.S. §§2801 *et seq.* and the regulations promulgated thereunder at 52 Pa.Code §§57.191-57.197; and sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240)(45 P.S. §§1201 and 1202) and the regulations promulgated thereunder at 1 Pa.Code §§7.1, 7.2 and 7.5; section 204(b) of the Commonwealth Attorneys Act (71 P.S. §732.204(b)); section 5 of the Regulatory Review Act (71 P.S. §732.204(b)); and section 612 of The Administrative Code of 1929 (71 P.S. §232) and the regulations promulgated thereunder at 4 Pa.Code §§7.251-7.235, we adopt the regulations set forth in Annex A; **THEREFORE,**
IT IS ORDERED:

1. That 52 Pa. Code, Chapter 57 is hereby amended by the addition of the regulations as set forth in Annex A, attached hereto.

2. That the Secretary submit this Final Rulemaking Order and Annex A for review and approval by the designated Standing Committees of both houses of the General Assembly, and for review and approval of the Independent Regulatory Review Commission.

3. That the Secretary shall submit this Order and Annex A to the Governor's Budget Office for review of fiscal impact.

4. That the Secretary shall submit this Order and Annex A to the Office of Attorney General for review as to legality.

5. That the Secretary certify this Order and Annex A and deposit them with the Legislative Reference Bureau to be published in the *Pennsylvania Bulletin.*

6. That the amendments to Chapter 57 embodied in Annex A shall become effective upon final publication in the *Pennsylvania Bulletin.*

7. That a copy of this Order and Annex A be filed in the folder regarding benchmarks and standards at M-00991220.

8. That the contact persons for this rulemaking are (technical) Blaine Loper, CEEP, (717)787-3810 and (legal) Elizabeth H. Barnes, Law Bureau, (717)772-5408.

9. That a copy of this Order and Annex A be served upon all electric distribution companies operating in Pennsylvania, the Office of Consumer Advocate, the Office of Small Business Advocate, the Energy Association of Pennsylvania, Senator Robert M. Tomlinson,

the Pennsylvania Utility Contractors Association, the IECPA, and the Pennsylvania AFL-CIO – Utility Caucus.

BY THE COMMISSION:

James J. McNulty
Secretary

(SEAL)

ORDER ADOPTED: May 22, 2008

ORDER ENTERED:

MAY 22 2008

ATTACHMENT A

12-Month Average Electric Reliability Indices for 2006

Customer Average Interruption Duration Index (CAIDI)				% Above (+) or Below (-) Standard	% Above (+) or Below (-) Benchmark
EDC	2006	Benchmark	Standard		
Allegheny Power	185	170	204	-9.3%	8.8%
Duquesne Light	**102**	108	130	-21.5%	**-5.6%**
Met-Ed (FE)	121	117	140	-13.6%	3.4%
Penelec (FE)	**108**	117	141	-23.4%	**-7.7%**
Penn Power (FE)	112	101	121	-7.4%	10.9%
PECO	133	112	134	-0.7%	18.8%
PPL	165	145	174	-5.2%	13.8%
UGI	**112**	169	228	-50.9%	**-33.7%**
Citizens	**68**	105	141	-51.8%	**-35.2%**
Pike County	**142**	174	235	-39.6%	**-18.4%**
Wellsboro	**91**	124	167	-45.5%	**-26.6%**
System Average Interruption Frequency Index (SAIFI)				% Above (+) or Below (-) Standard	% Above (+) or Below (-) Benchmark
EDC	2006	Benchmark	Standard		
Allegheny Power	1.16	1.05	1.26	-7.9%	10.5%
Duquesne Light	**0.79**	1.17	1.40	-43.6%	**-32.5%**
Met-Ed (FE)	**1.73**	1.15	1.38	**25.4%**	50.4%
Penelec (FE)	1.47	1.26	1.52	-3.3%	16.7%
Penn Power (FE)	1.22	1.12	1.34	-9.0%	8.9%
PECO	1.35	1.23	1.48	-8.8%	9.8%
PPL	**1.27**	0.98	1.18	**7.6%**	29.6%
UGI	**0.79**	0.83	1.12	-29.5%	**-4.8%**
Citizens	**0.14**	0.20	0.27	-48.1%	**-30.0%**
Pike County	**1.16**	0.61	0.82	**41.5%**	90.2%
Wellsboro	1.50	1.23	1.66	-9.6%	22.0%
System Average Interruption Duration Index (SAIDI)				% Above (+) or Below (-) Standard	% Above (+) or Below (-) Benchmark
EDC	2006	Benchmark	Standard		
Allegheny Power	215	179	257	-16.3%	20.1%
Duquesne Light	**81**	126	182	-55.5%	**-35.7%**
Met-Ed (FE)	**210**	135	194	**8.2%**	55.6%
Penelec (FE)	158	148	213	-25.8%	6.8%
Penn Power (FE)	137	113	162	-15.4%	21.2%
PECO	179	138	198	-9.6%	29.7%
PPL	**209**	142	205	**2.0%**	47.2%
UGI	**88**	140	256	-65.6%	**-37.1%**
Citizens	**10**	21	38	-73.7%	**-52.4%**
Pike County	165	106	194	-15.2%	55.3%
Wellsboro	**139**	153	278	-50.0%	**-9.2%**

Note: GREEN = better than benchmark; RED = worse than standard; BLACK = between benchmark and standard.

ATTACHMENT B

Three-Year Average Electric Reliability Indices for 2004-06

Customer Average Interruption Duration Index (CAIDI)				3-Year	3-Year	% Above (+) or
EDC	2004	2005	2006	Average	Standard	Below (-) Standard
Allegheny Power	190	195	185	**190**	187	**1.6%**
Duquesne Light	92	98	102	**97**	119	**-18.2%**
Met-Ed (FE)	128	122	121	**124**	129	**-4.1%**
Penelec (FE)	140	151	108	**133**	129	**3.1%**
Penn Power (FE)	120	151	112	**128**	111	**15.0%**
PECO	106	99	133	**113**	123	**-8.4%**
PPL	159	125	165	**150**	160	**-6.5%**
UGI	143	119	112	**125**	186	**-33.0%**
Citizens	64	116	68	**83**	115	**-28.1%**
Pike County	172	109	142	**141**	192	**-26.6%**
Wellsboro	84	105	91	**93**	136	**-31.4%**
System Average Interruption Frequency Index (SAIFI)				3-Year	3-Year	% Above (+) or
EDC	2004	2005	2006	Average	Standard	Below (-) Standard
Allegheny Power	1.13	1.15	1.16	**1.15**	1.16	**-1.1%**
Duquesne Light	1.03	0.98	0.79	**0.93**	1.29	**-27.6%**
Met-Ed (FE)	1.54	1.70	1.73	**1.66**	1.27	**30.4%**
Penelec (FE)	1.77	1.87	1.47	**1.70**	1.39	**22.5%**
Penn Power (FE)	1.43	1.56	1.22	**1.40**	1.23	**14.1%**
PECO	0.98	1.02	1.35	**1.12**	1.35	**-17.3%**
PPL	1.09	0.97	1.27	**1.11**	1.08	**2.7%**
UGI	0.65	0.64	0.79	**0.69**	0.91	**-23.8%**
Citizens	0.39	0.10	0.14	**0.21**	0.22	**-4.5%**
Pike County	0.52	1.85	1.16	**1.18**	0.67	**75.6%**
Wellsboro	3.13	1.37	1.50	**2.00**	1.35	**48.1%**
System Average Interruption Duration Index (SAIDI)				3-Year	3-Year	% Above (+) or
EDC	2004	2005	2006	Average	Standard	Below (-) Standard
Allegheny Power	216	224	215	**218**	217	**0.6%**
Duquesne Light	95	97	81	**91**	153	**-40.5%**
Met-Ed (FE)	197	209	210	**205**	163	**26.0%**
Penelec (FE)	248	284	158	**230**	179	**28.5%**
Penn Power (FE)	172	236	137	**182**	136	**33.6%**
PECO	104	100	179	**128**	167	**-23.6%**
PPL	173	121	209	**168**	172	**-2.5%**
UGI	93	76	88	**86**	170	**-49.6%**
Citizens	25	12	10	**16**	25	**-37.3%**
Pike County	90	202	165	**152**	129	**18.0%**
Wellsboro	263	144	139	**182**	185	**-1.7%**

Note: GREEN = better than standard; RED = worse than standard.

ANNEX A
TITLE 52. PUBLIC UTILITIES
Part 1. PUBLIC UTILITY COMMISSION
Subpart C. FIXED SERVICE UTILITIES
CHAPTER 57. ELECTRIC SERVICE

Subchapter N. ELECTRIC RELIABILITY STANDARDS

* * * * *

§57.192. Definitions.
The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

* * * * *

~~***Rural area*** **-- A rural place designated by the United States Bureau of Census as having a population of less than 5,000 and whose boundaries have been approved by the Secretary of the United States, Department of Transportation.**~~

* * * * *

~~***Urban area*** **-- An urbanized area or an urban place designated by the United States Bureau of Census as having a population of 5,000 or more and whose boundaries have been approved by the Secretary of the United States, Department of Transportation.**~~

* * * * *

§57.198. Inspection and maintenance standards.

~~**(a) An EDC shall have a plan for the periodic inspection and maintenance of poles, overhead conductors and cables, wires, transformers, switching devices, protective devices, regulators, capacitors, substations and other facilities critical to maintaining an acceptable level of reliability, in a format the Commission prescribes. The Commission will review each plan and may issue orders to ensure compliance with this section. The Commission may require an EDC to submit an updated plan at any time containing information the Commission may prescribe.**~~

~~**(1) The plan shall be based on industry codes, national electric industry practices, manufacturers' recommendations, sound engineering judgment and past experience. The plan shall be divided into rural and**~~

~~urban areas. The plan shall take into account the broad minimum inspection and maintenance intervals provided for in subsection (c).~~

~~(2) An EDC shall reduce the risk of future service interruptions by accounting for the age, condition, design and performance of system components and by providing adequate resources to maintain, repair, replace and upgrade the system.~~

~~(3) The plan shall include a program for the maintenance of minimum clearances of vegetation from the EDC's overhead transmission and distribution facilities sufficient to avoid contact under design-based conditions. The plan shall include a program for the trimming of tree branches and limbs located in close proximity to overhead electric wires when the branches and limbs may cause damage to the electric wires regardless of whether the trees in question are on or off of a right-of-way.~~

~~(4) The plan, or updates to the plan, shall form the basis of, and be consistent with, the EDC's inspection and maintenance goals and objectives included in subsequent annual and quarterly reliability reports filed with the Commission.~~

~~(b) On or before October 1, 2007, and every 2 years thereafter, an EDC shall submit its whole plan for the following calendar year to the Commission for review.~~

~~(1) Within 90 days, the Commission or its designee will accept or reject the plan.~~

~~(2) Absent action by the Commission or its designee to reject the plan within 90 days of the plan's submission to the Commission, or by January 1, whichever is later, the plan shall be deemed accepted. The acceptance shall be conditioned upon the EDC meeting Commission-established reliability performance standards.~~

~~(3) If the plan is rejected, in whole or in part, by the Commission or its designee, the EDC shall be notified of the plan's deficiencies and directed to resubmit a revised plan, or pertinent parts of the plan, addressing the identified deficiencies, or submit an explanation why the EDC believes its plan is not deficient.~~

~~(c) An EDC may request approval from the Commission for revising an approved plan. An EDC shall submit to the Commission, as an addendum to its quarterly reliability report, prospective and past revisions to its plan and a~~

~~discussion of the reasons for the revisions. Within 90 days, the Commission or its designee will accept or reject the revisions to the plan.~~

~~(d) An EDC shall maintain records of its inspection and maintenance activities sufficient to demonstrate compliance with its transmission and distribution facilities inspection, maintenance, repair and replacement programs as required by subsection (c). The records shall be made available to the Commission upon request within 30 days.~~

~~(e) An EDC shall maintain the following minimum inspection and maintenance intervals:~~

~~(1) Vegetation management. The statewide minimum inspection and treatment cycles for vegetation management are 4 years for distribution facilities and 5 years for transmission facilities.~~

~~(2) Pole inspections. Distribution poles shall be visually inspected every 10 years.~~

~~(3) Overhead line inspections. Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years. Distribution lines shall be inspected by foot patrol a minimum of once per year. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. Above-ground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle. Reclosers shall be inspected and tested at least once per year.~~

~~(4) Substation inspections. Substation equipment, structures and hardware shall be inspected monthly.~~

(A)*FILING DATE AND PLAN COMPONENTS.* EVERY 2 YEARS, BY OCTOBER 1, EACH EDC SHALL PREPARE AND FILE WITH THE COMMISSION A BIENNIAL PLAN FOR THE PERIODIC INSPECTION, MAINTENANCE, REPAIR, AND REPLACEMENT OF ITS FACILITIES THAT IS DESIGNED TO MEET ITS PERFORMANCE BENCHMARKS AND STANDARDS PURSUANT TO 52 PA. CODE §§ 57.191 – 57.197. EDCS IN COMPLIANCE GROUP 1, AS DETERMINED BY THE COMMISSION, SHALL FILE THEIR INITIAL PLANS ON OCTOBER 1, 2009. EDCS IN

COMPLIANCE GROUP 2, AS DETERMINED BY THE COMMISSION, SHALL FILE THEIR INITIAL PLANS ON OCTOBER 1, 2010. EACH EDC'S BIENNIAL PLAN SHALL COVER THE 2 CALANDAR YEARS BEGINNING 15 MONTHS AFTER FILING, BE IMPLEMENTED 15 MONTHS AFTER FILING, AND SHALL REMAIN IN EFFECT FOR 2 CALENDAR YEARS THEREAFTER. IN PREPARING THIS PLAN, THE FOLLOWING FACILITIES ARE CRITICAL TO MAINTAINING SYSTEM RELIABILITY:

(1) POLES.
(2) OVERHEAD CONDUCTORS AND CABLES.
(3) TRANSFORMERS.
(4) SWITCHING DEVICES.
(5) PROTECTIVE DEVICES.
(6) REGULATORS.
(7) CAPACITORS.
(8) SUBSTATIONS.

(B) THE PLAN SHALL BE CONSISTENT WITH THE NATIONAL ELECTRICAL SAFETY CODE, CODES AND PRACTICES OF THE INSTITUTE OF ELECTRICAL AND ELECTRONIC ENGINEERS, FEDERAL ENERGY REGULATORY COMMISSION REGULATIONS, AND THE PROVISION OF THE AMERICAN NATIONAL STANDARDS INSTITUTE, INC.

(C) THE PLAN SHALL COMPLY WITH INSPECTION AND MAINTENANCE STANDARDS SET FORTH IN SUBSECTION (N). A JUSTIFICATION FOR THE INSPECTION AND MAINTENANCE TIMEFRAMES SELECTED SHALL BE PROVIDED, EVEN IF THE TIMEFRAME FALLS WITHIN THE INTERVALS PRESCRIBED IN (N). HOWEVER, AN EDC MAY PROPOSE A PLAN THAT, FOR A GIVEN STANDARD, USES INTERVALS OUTSIDE THE COMMISSION STANDARD, PROVIDED THAT THE DEVIATION CAN BE JUSTIFIED BY THE EDC'S UNIQUE CIRCUMSTANCES OR A COST/BENEFIT ANALYSIS TO SUPPORT AN ALTERNATIVE APPROACH THAT WILL STILL SUPPORT THE LEVEL OF RELIABILITY REQUIRED BY LAW.

(D) THE PLAN SHALL SPECIFY FOR THE STANDARDS SET FORTH IN (N) ALL ROUTINE INSPECTION AND MAINTENANCE REQUIREMENTS, AND EMERGENCY MAINTENANCE PLANS AND PROCEDURES.

(E) THE PLAN SHALL BE DESIGNED TO REDUCE THE RISK OF OUTAGES BY ACCOUNTING FOR AGE, CONDITION,

TECHNOLOGY, DESIGN AND PERFORMANCE OF SYSTEM COMPONENTS AND BY INSPECTING, MAINTAINING, REPAIRING, REPLACING AND UPGRADING THE SYSTEM.

(F) THE PLAN SHALL INCLUDE A PROGRAM FOR THE MAINTENANCE OF CLEARANCES OF VEGETATION FROM THE EDC'S OVERHEAD DISTRIBUTION FACILITIES.

(G) THE PLAN SHALL FORM THE BASIS OF, AND BE CONSISTENT WITH, THE EDC'S INSPECTION AND MAINTENANCE GOALS AND OBJECTIVES INCLUDED IN SUBSEQUENT ANNUAL AND QUARTERLY RELIABILITY REPORTS FILED PURSUANT TO 52 PA. CODE §§ 57.193(C) AND 57.195 WITH THE COMMISSION.

(H) *REVIEW PROCEDURE.* WITHIN 90 DAYS OF RECEIPT OF THE PLAN, THE COMMISSION OR THE DIRECTOR OF THE BUREAU OF CONSERVATION, ECONOMICS, AND ENERGY PLANNING (CEEP) WILL ACCEPT OR REJECT THE PLAN IN WRITING.

(I) ABSENT ACTION BY THE COMMISSION OR THE DIRECTOR OF CEEP TO REJECT THE PLAN WITHIN 90 DAYS OF THE PLAN'S SUBMISSION TO THE COMMISSION, THE PLAN SHALL BE DEEMED ACCEPTED.

(J) IF THE PLAN IS REJECTED, IN WHOLE OR IN PART, BY THE COMMISSION OR THE DIRECTOR OF CEEP, THE EDC SHALL BE NOTIFIED OF THE PLAN'S DEFICIENCIES AND DIRECTED TO SUBMIT EITHER

(i) A REVISED PLAN, OR PERTINENT PARTS OF THE PLAN, ADDRESSING THE IDENTIFIED DEFICIENCIES, OR

(ii) AN EXPLANATION WHY THE EDC BELIEVES ITS PLAN IS NOT DEFICIENT. THE REVISED PLAN IS DEEMED ACCEPTED ABSENT ANY ACTION BY THE COMMISSION WITHIN 90 DAYS OF THE FILING.

(K) *APPEAL PROCEDURE.* AN EDC MAY APPEAL THE COMMISSION STAFF'S DETERMINATION UNDER SUBSECTION (H) BY FILING AN APPEAL UNDER 52 PA. CODE § 5.44 WITHIN 20 DAYS AFTER SERVICE OF NOTICE OF THE ACTION. A FINAL COMMISSION DETERMINATION IS APPEALABLE TO THE COMMONWEALTH COURT. ABSENT HAVING A GRANTED STAY, THE EDC IS OBLIGATED TO COMPLY WITH THE COMMISSION'S DIRECTIVES REGARDING ITS INSPECTION, MAINTENANCE, REPAIR AND REPLACEMENT PLANS.

(L) *EDC UPDATES.* AN EDC MAY REQUEST APPROVAL FROM THE COMMISSION FOR REVISING ITS APPROVED PLAN. AN EDC SHALL SUBMIT TO THE COMMISSION, AS AN ADDENDUM TO ITS QUARTERLY RELIABILITY REPORT PURSUANT TO 52 PA. CODE §§ 57.193(C) AND 57.195, PROSPECTIVE AND PAST REVISIONS TO ITS PLAN AND A DISCUSSION OF THE REASONS FOR THE REVISIONS. WITHIN 60 DAYS, THE COMMISSION OR THE DIRECTOR OF CEEP WILL ACCEPT OR REJECT THE REVISIONS TO THE PLAN. THE APPEAL PROCEDURE IN SUBSECTION (K) APPLIES TO THE APPEAL OF A REJECTION OF REVISIONS TO THE PLAN.

(M) *RECORD KEEPING.* AN EDC SHALL MAINTAIN RECORDS OF ITS INSPECTION AND MAINTENANCE ACTIVITIES SUFFICIENT TO DEMONSTRATE COMPLIANCE WITH ITS DISTRIBUTION FACILITIES INSPECTION, MAINTENENANCE, REPAIR AND REPLACEMENT PROGRAMS AS REQUIRED BY SUBSECTION (N). THE RECORDS SHALL BE MADE AVAILABLE TO THE COMMISSION UPON REQUEST WITHIN 30 DAYS. AN EXAMPLE OF SUFFICIENT RECORDS INCLUDES:

(1) DATE-STAMPED RECORDS SIGNED BY EDC STAFF WHO PERFORMED THE TASKS RELATED TO INSPECTION.

(2) MAINTENANCE, REPAIR AND REPLACEMENT RECEIPTS FROM INDEPENDENT CONTRACTORS SHOWING WHEN AND WHAT TYPE OF INSPECTION, MAINTENANCE, REPAIR OR REPLACEMENT WORK WAS DONE.

(N) *INSPECTION AND MAINTENANCE INTERVALS.* AN EDC SHALL MAINTAIN THE FOLLOWING INSPECTION AND MAINTENANCE PLAN INTERVALS:

(1) *VEGETATION MANAGEMENT.* THE STATEWIDE MINIMUM INSPECTION AND TREATMENT CYCLE FOR VEGETATION MANAGEMENT IS BETWEEN 4-8 YEARS FOR DISTRIBUTRION FACILITIES. AN EDC SHALL SUBMIT A CONDITION-BASED PLAN FOR VEGETATION MANAGEMENT FOR ITS DISTRIBUTION SYSTEM FACILITIES EXPLAINING ITS TREATMENT CYCLE.

(2) *POLE INSPECTIONS.* DISTRIBUTION POLES SHALL BE INSPECTED AT LEAST AS OFTEN AS EVERY 10-12 YEARS EXCEPT FOR THE NEW SOUTHERN YELLOW PINE (SYP) CREOSOTED UTILITY POLES WHICH SHALL BE

INITALLY INSPECTED WITHIN 25 YEARS, THEN WITHIN 12 YEARS ANNUALLY AFTER THE INITIAL INSPECTION. POLE INSPECTIONS SHALL INCLUDE:

(I) DRILL TESTS AT AND BELOW GROUND LEVEL.
(II) A SHELL TEST.
(III) VISUAL INSPECTION FOR HOLES OR EVIDENCE OF INSECT INFESTATION.
(IV) VISUAL INSPECTION FOR EVIDENCE OF UNAUTHORIZED BACKFILLING OR EXCAVATION NEAR THE POLE.
(V) VISUAL INSPECTION FOR SIGNS OF LIGHTENING STRIKES.
(VI) A LOAD CALCULATION.

(3) *POLE INSPECTION FAILURE.* IF A POLE FAILS THE GROUNDLINE INSPECTION AND SHOWS DANGEROUS CONDITIONS THAT ARE AN IMMEDIATE RISK TO PUBLIC OR EMPLOYEE SAFETY OR CONDITIONS AFFECTING THE INTEGRITY OF THE CIRCUIT, THEN THE POLE SHALL BE REPLACED WITHIN 30 DAYS OF THE DATE OF INSPECTION.

(4) *DISTRIBUTION OVERHEAD LINE INSPECTIONS.* DISTRIBUTION LINES SHALL BE INSPECTED BY GROUND PATROL A MINIMUM OF ONCE EVERY 1-2 YEARS. A VISUAL INSPECTION SHALL INCLUDE CHECKING FOR:

(I) BROKEN INSULATORS.
(II) CONDITIONS THAT MAY ADVERSELY AFFECT OPERATION OF THE OVERHEAD TRANSFORMER.
(III) OTHER CONDITIONS THAT MAY ADVERSELY AFFECT OPERATION OF THE OVERHEAD DISTRIBUTION LINE.

(5) *INSPECTION FAILURE.* IF CRITICAL MAINTENANCE PROBLEMS ARE FOUND THAT AFFECT THE INTEGRITY OF THE CIRCUITS, THEY SHALL BE REPAIRED OR REPLACED NO LATER THAN 30 DAYS FROM DISCOVERY.

(6) *DISTRIBUTION TRANSFORMER INSPECTIONS.* OVERHEAD DISTRIBUTION TRANSFORMERS SHALL BE VISUALLY INSPECTED AS PART OF THE DISTRIBUTION LINE INSPECTION EVERY 1-2 YEARS. ABOVE-GROUND PAD-MOUNTED TRANSFORMERS SHALL BE INSPECTED AT LEAST AS OFTEN AS EVERY 5 YEARS AND BELOW-GROUND TRANSFORMERS SHALL BE INSPECTED AT LEAST AS OFTEN AS EVERY 8 YEARS. AN INSPECTION SHALL INCLUDE CHECKING FOR:

(I) RUST, DENTS OR OTHER EVIDENCE OF CONTACT.
(II) LEAKING OIL.
(III) INSTALLATION OF FENCES OR SHRUBBERY THAT COULD ADVERSELY AFFECT ACCESS TO AND OPERATION OF THE TRANSFORMER.
(IV) UNAUTHORIZED EXCAVATION OR CHANGES IN GRADE NEAR THE TRANSFORMER.

(7) *RECLOSER INSPECTIONS.* THREE-PHASE RECLOSERS SHALL BE INSPECTED ON A CYCLE OF 8 YEARS OR LESS. SINGLE-PHASE RECLOSERS SHALL BE INSPECTED AS PART OF THE EDC'S INDIVIDUAL DISTRIBUTION LINE INSPECTION PLAN.

(8) *SUBSTATION INSPECTIONS.* SUBSTATION EQUIPMENT, STRUCTURES AND HARDWARE SHALL BE INSPECTED ON A CYCLE OF 5 WEEKS OR LESS.

PENNSYLVANIA PUBLIC UTILITY COMMISSION
HARRISBURG, PENNSYLVANIA 17105-3265

Revision of Pa. Code Chapter 57 Pertaining to Adding Inspection, Maintenance, Repair and Replacement Standards for Electric Distribution Companies

PUBLIC MEETING
MAY 22, 2008
MAY-2008-L-0021*
Docket No. L-00040167

STATEMENT OF COMMISSIONER KIM PIZZINGRILLI

In passing the Electricity Generation Customer Choice and Competition Act (the Act), the General Assembly emphasized that electric distribution companies should continue to ensure the safe and reliable provision of electric service to all customers. 66 Pa.C.S. §§ 2802(12), 2804(1), 2807(d). To achieve this objective, the Commission was charged with establishing inspection, maintenance, repair and replacement standards via regulation for the electric transmission and distribution system. 66 Pa.C.S. § 2802(20).

The Commission has previously promulgated regulations to establish reliability benchmarks and reporting requirements. *Rulemaking Re Amending Electric Service Reliability Regulations at 52 Pa. Code Chapter 57*, Docket L-00030161 (Final Rulemaking Order entered May 7, 2004). However, we had not promulgated specific regulations on the inspection, repair and maintenance of facilities.

These rules are the result of a process in which many comments have been filed and where there has been an extensive dialogue between staff and stakeholders. I commend all those involved for their efforts. I believe these rules reasonably balance the interests of all parties and serve the public interest by fostering safe and reliable electric service.

May 22, 2008
Date

Kim Pizzingrilli
KIM PIZZINGRILLI, COMMISSIONER

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PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH OF PENNSYLVANIA
HARRISBURG, PENNSYLVANIA

June 25, 2008

WENDELL F. HOLLAND
CHAIRMAN

The Honorable Arthur Coccodrilli
Chairman
Independent Regulatory Review Commission
14th Floor, Harristown II
333 Market Street
Harrisburg, PA 17101

Re: L-00040167/57-248
Final Rulemaking
Adding Inspection and Maintenance
Standards for EDCs
52 Pa. Code Chapter 57

Dear Chairman Coccodrilli:

Enclosed please find one (1) copy of the regulatory documents concerning the above-captioned rulemaking. Under Section 745.5(a) of the Regulatory Review Act, the Act of June 30, 1989 (P.L. 73, No. 19) (71 P.S. §§745.1-745.15) the Commission, on September 27, 2006, submitted a copy of the Notice of Proposed Rulemaking to the House Committee on Consumer Affairs, the Senate Committee on Consumer Protection and Professional Licensure and to the Independent Regulatory Review Commission (IRRC). This notice was published at 36 *Pa.B.* 6097, on October 7, 2006. In compliance with Section 745.5(b.1) copies of all comments received were provided to your Commission and the Committees.

In preparing this final form rulemaking, the Public Utility Commission has considered all comments received from the Committees, IRRC and the public.

Very truly yours,

Wendell F. Holland

Wendell F. Holland
Chairman

Enclosures
cc: The Honorable Robert M. Tomlinson
The Honorable Lisa Boscola
The Honorable Robert Godshall
The Honorable Joseph Preston, Jr.
Legislative Affairs Director Perry
Chief Counsel Pankiw
Regulatory Coordinator DelBiondo
Assistant Counsel Barnes
Mr. Loper
Judy Bailets, Governor's Policy Office

TRANSMITTAL SHEET FOR REGULATIONS SUBJECT TO THE REGULATORY REVIEW ACT

ID Number: L-00040167/57-248

Subject: Adding Inspection and Maintenance Standards for EDCs

Pennsylvania Public Utility Commission

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TYPE OF REGULATION

____	Proposed Regulation
____	Final Regulation with Notice of Proposed Rulemaking Omitted.
X	Final Regulation
____	120-day Emergency Certification of the Attorney General
____	120-day Emergency Certification of the Governor

FILING OF REPORT

Date	Signature	Designation
6-25-08	T Bauer	HOUSE COMMITTEE (Preston) Consumer Affairs
6/25/08	Mary Walmer	SENATE COMMITTEE (Tomlinson) Consumer Protection and Professional Licensure
6/25/08	[illegible]	Independent Regulatory Review Commission
		Attorney General
		Legislative Reference Bureau