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Materials from the January 22, 2007 Technical Conference

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2571

Inspection and Maintenance Standards

January 22, 2007 Technical Conference
Hearing Room 1, Commonwealth Keystone Building

AGENDA

9:00 AM Introduction of ALJ Kandace Melillo
All presenters will be given 15 minutes for a presentation. Questions from Commission staff and answers will follow each presentation.

Panel 1

Tanya McCloskey, Esquire
Office of Consumer Advocate

Scott Rubin, Esquire
AFL-CIO – Utilities Caucus

Panel 2

Robert Stoyko, Vice President Electric Division
UGI Utilities

Wayne Honath, Manager, Reliability & Standards
Duquesne Light Company

Bob Mattiuz, P.E., Director Distribution Engineering and Planning
Allegheny Power

David E. Schleicher, General Manager – Transmission/Distribution
PPL Electric Utilities Corporation

John E. McDonald, Vice President – Technical Services
Anthony Gay, Assistant General Counsel
PECO Energy Company

Eric Dickson, Director Operation Services
FirstEnergy

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Pike County, Citizens' and Wellsboro submitted written responses to the Commission's staff. Copies of these will be available at the meeting.

12:00 PM **Estimated time of Concluding Remarks**

PPL Electric Utilities Corporation

Inspection and Maintenance Standards

David E. Schleicher, P.E.

General Manager-
Transmission/Distribution
January 22, 2007

Introduction - Reliability

Drives customer satisfaction

- As a recipient of twelve J. D. Power Awards, PPL Electric is keenly aware that reliability is a principal driver of our customers' satisfaction.
- Reliability is integral to our mission to achieve superior customer satisfaction by providing safe, reliable and profitable electric delivery service.

Introduction - Reliability

Both qualitative and quantitative aspects

- Equipment reliability is a function of:
  - Asset type & quality
  - Climate, geography & environment
  - Maintenance practice
  - Operational wear & tear
- Reliability is measured by outage frequency, duration and number of customers affected.
- I&M is just one small part of reliability.

Q1. Periodic I&M Plans

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Equipment	Periodic Plan	Remarks
Poles	Yes	
Substations	Yes	
Protective Devices - Reclosers	Yes	
Protective Devices - Fuses	No	Inspections are targeted to those circuits with patterns of equipment failure. Regulator and capacitor electronic controllers are inspected annually.
OH conductors, cables, wires	T-Yes D-No	
Switching Devices	No	
Regulators	No	
Capacitors	No	
Transformers	No	Low non-lightning failure risk

Q2. I&M Cycles

Equipment	Intervals
Poles	▪SYP creosoted - initial @ 25 yr. ▪Other types - initial @ 10 yr. ▪subsequent vary from 1-9 yr. based upon prior inspection condition.
Substations	▪Bulk Power: Critical - weekly, non-critical - monthly. ▪Distribution: SCADA - quarterly, non-SCADA - monthly.
Protective Devices - Reclosers	▪Replaced @ 10 years ▪Controllers tested annually
Transmission OH conductors, cables, wires	▪Aerial patrol @ 1 yr. ▪Ground patrol @ 4 yr., except Susquehanna SES circuits @ 1 yr.

Q3. Intervals by Category

Category	Intervals
Vegetation	▪Transmission: inspect @ 3-5 yr., treat as needed. ▪Distribution 2006: circuits < 35 cust./mi. @ 8 yr., other circuits @ 5 yr.
Dist. Poles	▪SYP creosoted - initial @ 25 yr. ▪Other types - initial @ 10 yr. ▪subsequent vary from 1-9 yr. based upon prior inspection condition.
OH lines	▪Transmission: aerial patrol @ 1 yr., ground patrol @ 4 yr. except Susquehanna SES circuits @ 1 yr. ▪Distribution: no fixed interval, performance-based.
Substations	▪Bulk Power: Critical - weekly, non-critical - monthly. ▪Distribution: SCADA - quarterly, non-SCADA - monthly.

Q4. Annual cost comparison

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Activity	2006 Cost ($ million)	Annual Cost of NOPR ($ million)	
Vegetation	19.0	33.3	
Distribution poles	1.0	1.0	plus 1-time cost of $3 million
OH lines	3.4	15.4	
Substations	4.2	6.4	
Total	**27.6**	**56.1**	plus 1-time cost of $3 million

Q5. AFL-CIO cost/benefits

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- Further study required.
- Labor costs expected to be significantly higher than shown in response to Question 4.
- Rigid requirements will limit choices in design, quality, maintenance, operating procedures, and stifle innovation in technique and technology.
- Will provide more detailed comments by 4/16/07.

Q6. Repair time frames

- PPL Electric has a detailed repair priority system.
- EDC-specific priorities and time frames should be included in biennial plan submission, subject to Commission review and approval.
- Priorities and time frames are complex with too many EDC-specific variables to reasonably set state-wide.

Q7. OCA cost/benefits

- Same concerns as with Question 5 (AFL-CIO)
  - Further study required.
  - Labor costs expected to be significantly higher than shown in response to Question 4.
  - Rigid requirements will limit choices in design, quality, maintenance, operating procedures, and stifle innovation in technique and technology.
  - Will provide more detailed comments by 4/16/07.

Q8. Tree trimming cycles

- During 2001-05, a five-year period when PPL Electric matched our reliability benchmarks of 1994-98, our trim cycles were 8 years for circuits with density of less than 35 customers per mile and 5 years for all other circuits.
- Shorter intervals not necessary for maintaining PPL Electric's reliability.
- Intervals should be customized to each EDC's service area, climate and performance.

Q9. OH transformers

$2.6 million annually to inspect?

- No current inspection program for 370,000 OH transformers.
- Estimate assumes new program with contractors conducting inspections from the ground at a cost of about $7 per transformer.

Q10. Dist. Line Inspections

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Revise $ if substitute ground patrol for foot patrol?

- No, in preparing our estimates, PPL Electric interpreted "foot patrol" to mean the more general "ground patrol."
- If the intent is a walking patrol, the cost estimate will rise significantly.

PPL Electric's Perspective

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Inspection & Maintenance Standards

- Should be customized for each EDC to account for its unique asset structure, service area, technological sophistication, customer expectations and performance.
- Should easily adapt over time to changing technology, work methods, costs and structure.

PPL Electric's proposals

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I&M process based upon biennial plan submission

- EDCs should be divided into two groups, each submitting custom plans in alternate years.
- Commission reviews & identifies changes, if necessary.
- Revised plan, approved by Commission, sets standards for that EDC.
- EDC's quarterly reliability reports track progress against the approved plan.
- Commission enforces compliance with approved plan.

Additional questions?

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TECHNICAL CONFERENCE IN THE PROPOSED RULEMAKING FOR INSPECTION AND MAINTENANCE STANDARDS FOR ELECTRIC DISTRIBUTION COMPANIES

DOCKET NO. L-00040167

TESTIMONY OF JOHN E. McDONALD
PECO ENERGY COMPANY VICE-PRESIDENT,
TECHNICAL SERVICES

MONDAY, JANUARY 22, 2007, 9:00 A.M.

INTRODUCTION AND BACKGROUND

Good morning Your Honor and members of the Commission's Staff. I'm John McDonald, PECO Energy's Vice-President for Technical Services. Let me share my background with you. I have over 26 years of experience with the construction, operation and maintenance of PECO's electric transmission and distribution system.

As PECO's Vice-President for Technical Services, I direct all of PECO's activities related to the design and maintenance of the electrical system. This includes PECO's:

- Vegetation management programs;
- Reliability programs;
- Maintenance programs; and
- Programs establishing and updating PECO's equipment standards.

I also manage the budgets for these activities. Simply put, I'm responsible for making sure that funds are properly allocated and prioritized to maintain PECO's electric reliability.

TESTIMONY

Good Maintenance is Good Business

Thank you for giving me the opportunity to make this presentation today on electric reliability standards. Providing safe, reliable service ***is what we do at PECO***. We operate an electric utility system. We take pride in our work, and we strive to be the best electric utility company we can be for our customers.

Electric system safety and reliability are important to PECO. ***They are good for our customers. They are good for our workers. They are good for our business.*** Here's why:

- First, electricity is an essential service. Our customers rely on us to provide safe and reliable electricity.
- Second, we consider customer satisfaction to be a key business goal. Outages are contrary to that goal because they can cause customers to be dissatisfied.
- Third, a reliable system is safe for our workers. We want our workers to be safe, healthy and productive.
- Fourth, when we have outages, we have to make repairs on an emergent basis. Emergent repairs are not the optimal use of our resources and often are completed at a premium.

The bottom line: We agree with the Commission's ultimate goal in this rulemaking docket – maintaining the reliability of our electric system. We also agree with the critical principle the Commission recognized in its proposed rulemaking order and that Staff has recognized in convening this session: ***Inspection & Maintenance rules must be reasonable and their costs should not outweigh their benefits.***

How to Maintain Electric Reliability

What is the best way to maintain electric system reliability? The answer to this question will be different for every electric distribution company. It will be different based on the geographic and weather conditions in the EDC's operating territory. It will be different based on the ***size*** of the EDC's operating territory. It will be different based on the types of equipment the EDC uses. It will be different based on the equipment's fundamental system design, operating voltages, and the age of the facilities. Moreover, the answer for each EDC ***may*** be different a year from now. That's because improvements in technology and maintenance methods occur continuously.

This is why PECO is asking that the Commission to allow each EDC to submit individual, condition- and equipment-based Inspection & Maintenance plans for the Commission's approval, instead of imposing rigid "one size fits all" rules on the EDCs. We're willing to be held to our plans, and let our reported reliability metrics be the measurement of their effectiveness. What we are asking for is ***flexibility*** to achieve the Commission's reliability goals within a plan that suits our systems' requirements.

It is important to note that PECO's Inspection & Maintenance Programs have proven to be effective. Our reliability in the last five years has been better than the five years proceeding electric restructuring. In fact, PECO has filed 12 consecutive quarterly reports stating that our reliability indexes have exceeded PUC standards.

Vegetation Management

I would like to take a moment to explain PECO's current vegetation program. PECO's vegetation program uses both a ***time-based*** and ***condition-based*** approach. Our time-based program includes:

- A comprehensive vegetation treatment that incorporates trimming, hazard and strategic tree removal, and herbicide treatment every five years.

Our condition-based program includes:

- A mid-cycle inspection of all circuits between the second and third year of the five year cycle to identify fast growing trees which will be trimmed to clearance until the next schedule cycle trimming; and
- A 34kV program that annually inspects 34kV circuits not in the current or previous year's schedule for fast growing trees and trims them to clearance until the next cycle trimming.

We believe – and our experience has shown – that these are the most appropriate and effective vegetation management practices for maintaining distribution system reliability.

The Commission's proposed vegetation management rule sets a minimum four-year inspection and treatment cycle for distribution facilities. Our experience has shown that is not the right approach. First, an inflexible four-year treatment cycle for distribution facilities would increase PECO's vegetation management costs by ***$5 million per year*** but would have minimal impact on PECO's electric reliability. Second, the rule puts the focus on a prescriptive time schedule as opposed to the program employed by PECO – a program that is tailored to actual vegetation conditions.

Vegetation management is by its nature an organic process and a ***condition-based*** approach provides our customers with the highest level of reliability. A static four-year program would provide minimal improvement in reliability, and would not be a prudent use of valuable funds.

Distribution Line Inspections

The proposed rule requiring annual foot patrol inspections for distribution lines is another area that would result in significantly increased costs for PECO with no tangible reliability benefits. Our current program is a two-year ground patrol inspection program – meaning, we use vehicles to inspect the majority of our system and foot patrols for rear property inspections.

First, requiring EDCs to inspect distribution lines and transformers by foot is inconsistent with today's technology. Visual foot patrols may have been reasonably necessary years ago – and may still be prudent in limited circumstances in areas not accessible by vehicle – but in PECO's service territory, most distribution facilities can and should be inspected by vehicle. PECO uses thermographic imaging and computer equipment to discover problems or "hot spots" on distribution lines, transformers and electrical connections.

For example, you can see in our PowerPoint slide a picture of a terminal pole demonstrating what can be seen by the visual inspection that is being proposed in the draft rules as part of the foot patrol. This is the station leg terminal pole that provides service to 456 customers on our

Whitemarsh 163 circuit, including KYW News Radio's transmitting tower. The cable terminators that you see next to the bottom arrow and the disconnect switches next to the top arrow all look pretty good to a person doing a visual inspection on foot.

However, this next slide is a picture of the same pole as seen through a thermographic camera lens. The picture is indicating two hot spots at the terminator and at the bottom of the disconnect. The report indicates that the white color represents a temperature of 279 degrees Celsius, or 249 degrees above the reference temperature. This line was switched out immediately and repairs made without any interruption of service to our customers, including KYW News Radio. This is information that cannot be detected by the naked eye.

In addition, under our current system, a record file of the trouble spot is created and entered into a database. The information is electronically transmitted and provides the workers in the field with a clear and concise picture of what maintenance is required to resolve the issue. In order to do this type of inspection, a person would need to carry a thermographic camera, laptop computer, digital camera, and circuit prints. From this example, you can see that it is not possible to carry all of this equipment on foot and perform the inspection efficiently on foot. Vehicle inspections allow us to cover more ground than foot patrols and thereby inspect more equipment for maintenance issues.

The PUC's proposal of doing a foot patrol will significantly increase PECO's circuit inspection costs by $3.5 million each year. Staff asked in its written questions how the proposed rules might reduce reliability. This is a clear example of such a case. The proposed rules' requirement of a visual inspection of our facilities by someone conducting a foot patrol will increase costs and reduce reliability. The technology and processes we use today provide a significant improvement to reliability. This is why we have advocated "ground patrol" inspections.

I am also concerned with the 30-day repair schedules proposed in the rules with respect to distribution and transmission line inspections, which were originally proposed by the AFL-CIO and the OCA, as well as their proposed replacement schedule for poles, because they will further increase costs and reduce reliability. Based upon our daily monitoring of the conditions on our system, and our decades of experience, PECO assigns a priority and schedule to every emergent maintenance job.

We can't always take a customer out of service to repair a problem within 30 days. For example, Underground Residential Development cable replacement crossing Pennsylvania State roads require state permits that take 6 to 8 weeks to obtain. In addition, we are required to get permission from PJM to take transmission lines out of service to avoid impacting other EDCs and their customers, and to maintain transmission grid stability. Based on the type of repair required, this may take several months.

We need the flexibility to allocate and prioritize our resources to maintain system reliability. Here's another example. We had sixteen major storm events last year. When storms hit, our priority is to restore service to our customers as quickly as possible. Once all customers are restored, we focus our attention on making permanent repairs to restore our system to normal.

One of my concerns is that with prescriptive standards, like the ones being considered, an EDC will be faced with a choice of either missing the standards in such situations or continually asking the Commission for waivers.

Prescriptive rules, by their nature, often distort the priorities of jobs and prevent EDC's from dynamically deploying resources to focus on high priority situations. That's not good for reliability and that's not good for our customers.

CONCLUSION

I want to conclude by summarizing PECO's position on the proposed inspection and maintenance standards. PECO supports the Commission's ultimate safety and reliability goals. In the interest of time, our positions on the rest of the proposed Inspection and Maintenance Standards are outlined in the written response to your questions. We have focused only on the two most expensive issues. However, PECO's costs would increase by almost $11 million if we had to meet the proposed I&M standards.

Electric system reliability is good for our customers, good for our workers and good for our business.

PECO does not support **inflexible** rules that have no beneficial or measurable impact on reliability, that do not take system conditions and new technologies into account, and that instead result in significant costs that must be passed on to customers or taken from other, productive Inspection and Maintenance programs.

We're willing to follow and be held accountable to the individual plan we submit to the Commission, and to let our reported reliability metrics be the measurement of our plan's effectiveness. We are asking the Commission to strike the correct balance by allowing PECO and other EDCs the flexibility to achieve the reliability goals we share. Again, thank you for this opportunity to appear before you. I will be happy to answer any further questions you may have.

Summary of Comments of Pa. AFL-CIO Utility Caucus: Electric Inspection and Maintenance Standards

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January 22, 2007

Need for Standards

- Required by law (66 Pa. C.S. § 2802(20)):
  "... the Commission *shall set through regulations*, inspection, maintenance, repair and replacement standards and enforce those standards."
- Recommended by FERC. As PUC stated in 2005 Reliability Report (Aug. 2006):
  "New information arising out of the blackout in August 2003 formed a basis for further evaluating the need for inspection and maintenance standards. One of the causes of the blackout was the failure to adequately manage tree growth along transmission lines. ... The resulting FERC report to Congress recommended that oversight organizations should work ... to develop *measurable and achievable program objectives* to identify what can be done to reduce the likelihood of a recurrence of tree and power line conflicts."

Impact of Restructuring

EDC performance deteriorated significantly. SAIDI (in minutes) as an example:

	1994	1999	2005
Allegheny	147	169	224
Duquesne	115	113	97
MetEd / Penelec	120	128	209 / 284
PECO	156	198	100
PPL	92	132	121

Why Did This Happen?

- Restructuring law changed the incentives
  - Encouraged unregulated investments
  - Long-term rate cap provided no incentive to invest in regulated distribution operations
- Many EDCs allowed their systems to deteriorate and have adopted “run until fail” maintenance practices, jeopardizing safety and reliability and increasing long-term costs

Relationship Between I&M Standards and Reliability Standards

- I&M standards ensure the long-term safety, reliability, and cost-effective distribution of electric service
  - Reliability standards are current measures of reliability performance
  - I&M standards are long-term, forward-looking standards – focused on safety, reliability, and cost

Elements of Reasonable Standards

- Inspection and preventive maintenance of critical facilities
- Repair / replacement of dangerous facilities
- Proactive management of vegetation

Why Prescriptive Standards?

- EDCs have shown inability to adopt reasonable practices focused on long-term safety, reliability, and cost-effectiveness
- Should have been adopted prior to restructuring, which could have prevented drastic changes in I&M practices
- Adopting them now will at least prevent unintended consequences from surfacing in the future

Specific Standards

- Utility-specific plans
- Minimum I&M intervals for distribution facilities:
  - 10 years for pole inspections
  - 1 year for above-ground lines (visual)
  - 2 years for pad-mounted and underground transformers
  - Monthly for substations
  - 4 years for substation breakers
  - 1 year for vaults serving special needs (hospitals, schools)
  - 2 years for other critical facilities (switches, relays, sectionalisers)
- Vegetation management cycles - 4 years

Penalties for Non-Compliance

- Automatic for failure to repair / replace safety hazards within stated time period
- Others – PUC investigation, action plans, or other administrative action

Recent Delaware I&M Standards

- In September 2006, the Delaware PSC published final electric reliability, inspection, and maintenance standards, including:
  - "Each EDC *shall inspect and maintain* as necessary its power transformers, circuit breakers, substation capacitor banks, automatic 3-phase circuit switches and all 600 amp or larger manually operated, gang transmission circuit tie switches *at least once every two (2) years*." (§ 7.2)
  - "Each EDC *shall inspect all right-of-way vegetation at least once every four (4) years* and trim or maintain as necessary, according priorities to circuits that have had significant numbers of vegetation-related outages, while not unduly delaying the trimming of other circuits that inspections indicate currently need trimming. *Vegetation management practices should be applied at least once every four (4) years* except where growth or other assessments deem it unnecessary." (§ 7.3)

  Code of Dela. Regs. 10-800-052, effective Sept. 10, 2006

Costs and Benefits

- Minimum standards proposed by AFL-CIO consistent with standard utility practices prior to restructuring
- Do not know source of EAPA estimated $75 million cost for compliance
- If accurate, result of EDC cost-cutting during past 10 years
  - EDCs have saved much more than $75 million per year by reducing work force and changing maintenance practices
- Customers have been paying the price for that cost cutting through diminished reliability

Conclusion

- I&M standards are required by law
- I&M standards could have helped prevent steep decline in reliability experienced since restructuring
- I&M standards are future-oriented: safety, reliability, and cost
- Recent Delaware I&M standards consistent with Pennsylvania proposals

Wellsboro Electric Company Responses for January 22, 2007, Technical Conference on Proposed Regulations For Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection and Maintenance Standards for Electric Distribution Companies
Docket No. L-00040167

Q1. Does your company have a periodic I&M plan for each type of equipment listed above? If not, please explain why not. Provide specific explanations in your response for each type of equipment.

If your company does have a periodic I&M plan for the equipment listed above, please list the I&M cycles that are followed for each type of equipment.

Response:

See attached spreadsheet at Appendix "A".

Q2. 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.

Response:

Wellsboro Electric Company's ("WECO") Vegetation Management is currently on an 8-year cycle. See Appendix "A".

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

Response:

WECO inspects its poles on a 10-year cycle. See Appendix "A".

(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 belowground transformers shall be inspected on a 2-year cycle. Reclosers shall be inspected and tested at least once per year.

Response:

WECO inspects all single-phase lines on a 3-year cycle, three phase lines on a 2-year cycle, and any overhead transformers follow the same cycle as single and three phase lines. WECO inspects underground lines and transformers on a 2-year cycle. In addition, reclosers are tested as part of the circuit patrol, but in case of trouble on the circuit, during a blink patrol, counter reading of OCR'S are taken twice per year. Reclosers are then removed from service for testing and calibration on a 6-year cycle or 100 operations, whichever comes first.

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

Response:

WECO inspects substation equipment monthly. No additional cost would be incurred to satisfy the proposed interval.

Q3. For each of the four I&M intervals listed above, what are the I&M intervals utilized by your company?

Response:

Please see above.

Q4. For each of the four I&M intervals, what is an estimate of the annual cost to convert from your company's current interval to those proposed above.

Response:

See Appendix "A".

Q5. If the Commission were to adopt the cited Annex A Version in the AFL-CIO's comments, what would the cost be?

Response:

To the extent requirements in the Commission's proposed regulations are similar to the AFL-CIO proposal, the cost estimate in Appendix "A" would apply. WECO is still developing its calculation of the incremental cost of the AFL-CIO proposal.

Wellsboro Electric Company Responses for January 22, 2007, Technical Conference on Proposed Regulations For Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection and Maintenance Standards for Electric Distribution Companies Docket No. L-00040167

Q6. If the Commission were to adopt minimum repair standards and time frames for corrective actions, what would your EDC recommend they be?

Response:

WECO does not believe that minimum inspection and repair timelines are either necessary or efficient for Pennsylvania EDCs. WECO believes that it is important for each individual EDC to maintain the necessary flexibility to manage its operations based on the specific conditions under which the EDC operates. For example, maintenance practices for rural areas vary greatly from those in more urban areas. WECO does not believe that strict timelines to correct defects in the system are needed as such timelines will do very little to increase or maintain reliability. Problems spotted during inspections vary in severity, while some problems found may need immediate attention others may not be present a problem and can be scheduled for future repair without affecting the normal work schedule. At WECO, our line crews perform all maintenance activity for substations, the overhead and underground distribution system, build line extensions for new services, and construct or rebuild all system improvement work. Mandating strict timelines will only impede our ability to schedule these necessary and important activities.

The Commission has already established reliability indices for all EDCs. These indices already provide the Commission with the tools to determine if EDC's current inspection and maintenance standards are sufficient. The Commission also has the ability to impose more stringent inspections and maintenance standards if an EDC fails to meet established standards.

Q7. What are your objections, if any, to a 4-year tree trimming cycle for distribution lines? Would you accept a 5 or 6-year tree-trimming cycle? Would you prefer an average tree-trimming cycle as proposed by Duquesne Light?

Response:

Mandating cycles for right-of-way management needs to be left to the EDC. As previously discussed, the EDCs' service territories vary greatly in terrain, tree species, weather, and regulations from local authorities such as Borough Councils, Shade Tree Commissions, Township Supervisors, etc. Each EDC needs the flexibility to maintain its vegetation management programs based on the conditions under which it operates.

PA PUC Proposed Rulemaking on Inspection and Maintenance Standards
Major Items

Maintenance Items

Subject	PUC Proposal	Current Practice	Potential Impact	Estimated Cost and/or Resource Impact
1) Vegetation Management	Four Year Cycle	Eight Year Cycle	Double current R.O.W. Program annually, additional staff time to administer contracts,inpect work, handle customer issues estimated additional staff cost of $20,000	$195,000 additional annual cost
2) Pole Inspections	Ten year	Ten Year	Minimal	
3) Overhead Line Inspection	Annual foot patrol	Five year Cycle	Additional staff time for contracts, additional time for data entry into mapping system to track inspections, estimated cost of $10,000	$88,000 additional annual cost
Overhead Transformer inspection			Included in line inspection	
Underground Transformer Inspections	Every Two years	Five Years	Addiitional staff time for entry into mapping system to track inspection	$15,000
OCR Inspection and testing	Annual testing	Five Years or 250 Operations		$35,000
4) Substation Inspections	Monthly	Monthly		

Miscellaneous Items

Subject	PUC Proposal	Current Practice	Potential Impact	Estimated Cost and/or Resource Impact
Plan Submission	Every Two Years	Five Years		5,000
Miscellaneous Items			Purchase of additional OCR's to have in stock for	$140,000
TOTAL ANNUAL PROGRAM COST AS ESTIMATED BY WECO				**$478,000.00**

APPENDIX "A"

PECO
An Exelon Company

Proposed Rulemaking
Inspection & Maintenance Standards
Technical Conference

Docket No. L-00040167

John E. McDonald
Vice President - Technical Services
PECO Energy Company

January 22, 2007

Witness Background – John E. McDonald

PECO
An Exelon Company

- 26 years of experience constructing, operating and maintaining PECO's electric transmission and distribution system
- Vice President for Technical Services
  - ➔Direct all PECO activities related to designing and maintaining it's electric system
  - ➔These activities include:
    - Vegetation management programs
    - Reliability programs
    - Maintenance programs
    - Distribution equipment standards
    - Establishing budgets for the activities

Good Maintenance is Good Business

PECO
An Exelon Company

- Providing safe, reliable service ***is what we do***.
- A reliable system is good for our customers and our workers.
- Good maintenance programs prevent:
  - ➔ Unsafe conditions
  - ➔ Customer dissatisfaction
  - ➔ Service outages
  - ➔ Unscheduled and expensive emergency repairs
- Good maintenance programs require flexibility to incorporate experience, new equipment and technology to optimize performance results.
- ***Inspection and Maintenance rules must be reasonable and their costs should not outweigh their benefits.***

How to Maintain Electric Reliability

PECO
An Exelon Company

- The answer will be different for every electric distribution company (EDC).
  - ➔Different geography and weather conditions
  - ➔Different size service territory
  - ➔Different types of equipment used
  - ➔Different system design, operating voltages and age
- The answer for each EDC may be different a year from now.
- PECO recommends that each EDC submits individual, condition and equipment based I&M plans for Commission approval
  - ➔Use reported reliability metrics as the measurement of effectiveness
- PECO's I&M Programs have proven to be effective.

PECO's Current Vegetation Plan

PECO. An Exelon Company

- PECO's program uses both a ***time-based*** and ***condition-based*** approach.
- Time-based:
  - ➔ Five year Comprehensive Program
    - Trimming
    - Tree removals (hazardous and strategic)
    - Herbicide Applications
- Condition-based:
  - ➔ Mid-cycle Program
    - Identify fast growing trees and trim to clearance until cycle trimming
  - ➔ 34 kV Program
    - Annually Inspect 34 kV circuits not in the current year schedule to identify fast growing or problematic trees that need to be addressed

Vegetation Management

PECO
An Exelon Company

- Adopting the PUC proposal of a four year trim cycle would increase PECO's vegetation management costs by ***$5 million per year*** but would have only minimal impact on PECO's electric reliability.
- Vegetation management is by its nature an organic process and a ***condition-based*** approach provides our customers with the highest level of reliability.
- For these reasons, a static four-year program would not be a prudent use of valuable funds.

Distribution Line Inspections

PECO
An Exelon Company

- PECO inspects its distribution facilities every two years using thermographic imaging and computer equipment, which requires the use of a vehicle.

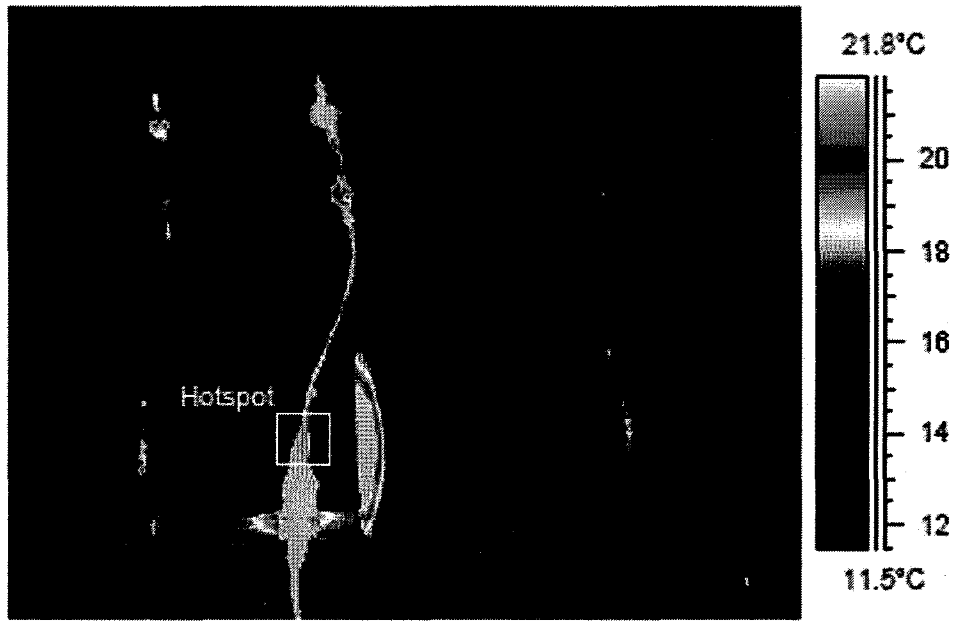
- This technology is very effective in discovering trouble spots on the system.

Distribution Line Inspections

PECO
An Exelon Company

Distribution Line Inspections

TEMP RISE (C)	REPAIR PRIORITY
249	1



Ambient Temp (C)	Ref Temp (C)	Hotspot Temp (C)
18	24	>272.7°C

Distribution Line Inspections

PECO
An Exelon Company

EMERSON.
Process Management

610-490-3239

INFRARED THERMOGRAPHY REPORT

COMPANY: PECO ENERGY

DATE: 09/06/2006

REGION: Montgomery County

CIRCUIT #: Whitemarsh-163

QUAD #: 32-C3-E6

POLE #: 50158

ADDRESS/ CITY: Militia Hill Rd 2 poles south of Skippack Pike

TOWNSHIP (POLITICAL SUB): Whitemarsh-558

EQUIP TYPE: Primary Terminator (pothead)

PORTION OF CIRCUIT: Primary

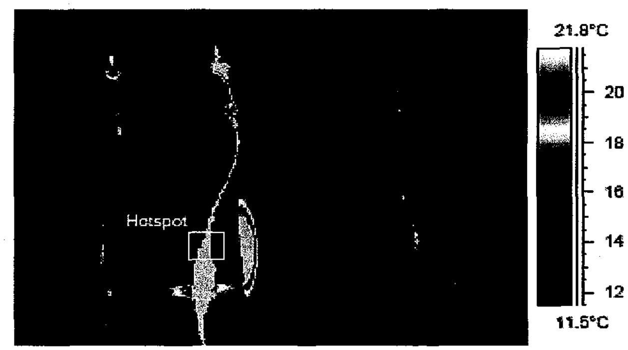
INFRARED INSPECTOR: Gary Gilbert

PROBLEM PHASE: [ ] STREET SIDE [X] CENTER [ ] GRASS SIDE [ ] N/A

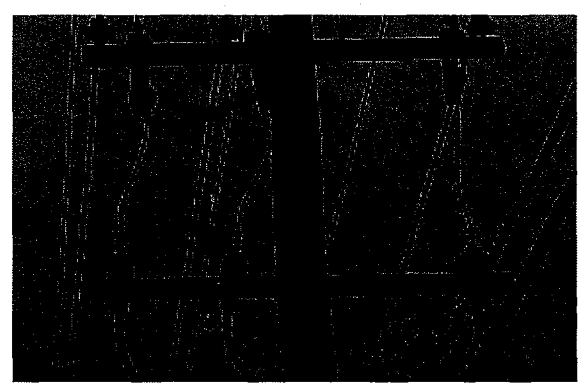
COMMENTS: 2 bolt pad connection on pothead. Check also jaw end of center phase disconnect. Station Leg Terminal Pole.

Problem Sequence #: M-436

TEMP RISE (C)	REPAIR PRIORITY
249	1



Ambient Temp (C)	Ref Temp (C)	Hotspot Temp (C)
18	24	>272.7°C



Fixed Repair Schedules

PECO
An Exelon Company

- PECO assigns a priority and schedule to every maintenance and trouble job.
  - ➔Daily meetings are held to review emergent work and set priorities based on safety and system reliability.
- Fixed repair schedules will increase costs and may eventually reduce reliability.
  - ➔Storms and service emergencies would make meeting fixed repair schedules impractical and very expensive.
  - ➔Being subservient to fixed repair schedules and penalties may distort job priorities.
  - ➔With fixed repair schedules, there is little flexibility in scheduling the work effectively.
- AFL-CIO proposal of fixed repair schedules will not increase service reliability.

Conclusions

PECO
An Exelon Company

- PECO supports the Commission's reliability goals.

- Electric system reliability is:
  - ➔Good for our customers
  - ➔Good for our workers
  - ➔Good for our business

- PECO is willing to be held to the plan we submit to the Commission and to let our reported reliability metrics be the measurement of our effectiveness.

Proposed Rulemaking
Inspection & Maintenance Standards
Technical Conference

Docket No. L-00040167

Attachment "A" To The Testimony of

John E. McDonald
PECO Vice President – Technical Services

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Proposed Rulemaking for Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection and Maintenance Standards for the Electric Distribution Companies	: : : : :	**Docket No. L-00040167**

PECO ENERGY COMPANY'S RESPONSES TO STAFF'S QUESTIONS FOR INTERESTED PARTIES TO ADDRESS AT THE JANUARY 22, 2007 TECHNICAL CONFERENCE

Pursuant to the Commission's January 9, 2007 Secretarial Letter in this docket, PECO Energy Company ("PECO") hereby responds to Staff's questions concerning the comments filed by interested parties on November 6, 2006.

QUESTION NO. 1

Proposed Section 57.198 (Inspection and maintenance standards) provides:

> (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.

Does your company have a periodic I&M plan for each type of equipment listed above? If not, please explain why not. Provide specific explanations in your response for each type of equipment.

PECO'S RESPONSE TO QUESTION NO. 1

Yes, PECO has a periodic I&M plan for each type of equipment listed in Proposed Section 57.198(a).

QUESTION NO. 2

If your company does have a periodic I&M plan for the equipment listed above, please list the I&M cycles that are followed for each type of equipment.

PECO'S RESPONSE TO QUESTION NO. 2

Please see the attached Excel spreadsheet labeled "PECO's Response to Staff's I&M Question No. 2. – PECO's Periodic I&M Plan."

QUESTION NO. 3

(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.

For each of the four I&M intervals listed above, what are the I&M intervals utilized by your company?

PECO'S RESPONSE TO QUESTION NO. 3

Please see the attached Excel spreadsheet labeled "PECO's Response to Staff's I&M Questions Nos. 3-4 – PECO's I&M Intervals." Refer to the column labeled "Current PECO Practice."

QUESTION NO. 4

For each of the four I&M intervals, what is an estimate of the annual cost to convert from your company's current interval to those proposed above?

PECO'S RESPONSE TO QUESTION NO. 4

Please see the attached Excel spreadsheet labeled "PECO's Response to Staff's I&M Questions Nos. 3-4 – PECO's I&M Intervals." Refer to the column labeled "Estimated Annual Incremental Cost."

QUESTION NO. 5

For PECO, how could implementation of the proposed regulations reduce reliability by taking PECO's attention away from more important inspection and maintenance projects? What other more important projects are you referring to?

PECO'S RESPONSE TO QUESTION NO. 5

Static prescriptive rules do not keep pace with technology and the focus on schedules – as opposed to conditions – which often do not have a measurable or immediate impact on reliability. This can distort EDC priorities and prevent them from deploying resources to focus on emergent or high priority situations.

The draft regulation requiring that distribution lines and overhead transformers be inspected by foot patrols (Proposed § 57.198(e)(3)) is an example. PECO currently inspects its distribution lines and overhead transformers through a ground patrol using vehicles primarily and foot patrols where necessary. Vehicles enable PECO to inspect these facilities through the use of thermographic imagery, computer equipment and maps. Thermographic equipment allows PECO's personnel to see hot spots that are not visible to the naked eye. Computer equipment and maps allow PECO to enter trouble information into its information systems so that the information can be recorded and managed on a priority basis. The proposed requirement of foot patrols will mean that PECO would not be able to spot troubles as effectively and efficiently as it does under its current practice. In addition, it would add $3.5 million to PECO's annual I&M budget.

Another example relates to storm events. PECO's service territory experienced sixteen major storm events this year. When the storms hit, PECO's priority was to get customers who were out of service back in service as quickly as possible. If prescriptive standards were in place, repair priorities could have been distorted as a result of an emphasis on time-based standards instead of conditions.

QUESTION NO. 6

If the Commission were to adopt the edited Annex A version in the AFL-CIO's comments dated November 4, 2006, what would those changes to the regulations cost Pennsylvania ratepayers? Please justify an aggregate figure with specifics. Would the proposed additions to the proposed regulations better reliability performance in the EDC industry?

PECO'S RESPONSE TO QUESTION NO. 6

Please see the attached Excel spreadsheet labeled "PECO's Responses to Staff's I&M Question No. 6" for the projected costs of the AFL-CIO's recommendations. Those proposed additions to the draft regulations would not efficiently or effectively improve overall reliability performance in the EDC industry. First, they are focused on prescriptive time schedules. Second, their projected costs outweigh their benefits. If budgets were unlimited and rates were increased without regard to the impact on ratepayers, increasingly prescriptive I&M requirements could result in some minimal improvements in reliability. However, the question before the

Commission is whether the costs of proposed regulations outweigh the reliability benefits that may result from their implementation.

QUESTION NO. 7

If the Commission were to adopt minimum repair standards and time frames for corrective actions, what would your EDC recommend they be?

PECO'S RESPONSE TO QUESTION NO. 7

Please see the attached Excel spreadsheet labeled "PECO's Response to Staff's I&M Questions Nos. 3-4 – PECO's I&M Intervals." Refer to the column labeled "Current PECO Practice."

QUESTION NO. 8

Do you have any criticisms of the OCA's proposed revision to Annex A, and if so, what are they? What would the cost be to ratepayers if any in implementing the proposed regulations in Annex as revised by OCA? What would the benefit be?

PECO'S RESPONSE TO QUESTION NO. 8

PECO's criticisms of the OCA's proposed revisions are the same as those PECO identified with regard to the AFL-CIO's proposed revisions.

For the cost impact of the OCA's proposed revisions, please see the attached Excel spreadsheet labeled "PECO's Response to Staff's I&M Question No. 8."

Given the limited amount of time provided for these responses (six business days) PECO cannot answer Staff's final question.

QUESTION NO. 9

What are your objections, if any, to a 4-year tree trimming cycle for distribution lines? Would you accept a 5 or 6-year tree-trimming cycle? Would you prefer an average tree-trimming cycle as proposed by Duquesne Light?

PECO'S RESPONSE TO QUESTION NO. 9

PECO objects to a 4-year tree trimming cycle because this cycle would increase PECO's vegetation management costs by $5 million per year but would only have a minimal impact on PECO's electric reliability. As PECO has set forth in its comments and testimony, a condition-based I&M plan for vegetation management (as well as the other I&M categories discussed in the proposed regulations), is the most effective and efficient way to maintain electric system reliability.

In response to Staff's second question, and without waiver of the foregoing, PECO could accept a 5 or 6-year tree-trimming cycle that focused on vegetation conditions and not simply time schedules.

In response to Staff's third question, Duquesne Light proposed "an average, rather than minimum cycle, so that those lines needing more attention can be trimmed on cycles that are shorter than the mandated requirement and those not requiring management . . . will be subject to a longer than average cycle." Duquesne's Nov. 6, 2006 Comments at 5. Duquesne further recommended that the vegetation management cycle be set at 6 years for distribution lines and 7 years for transmission lines. PECO believes that an average trimming cycle, as proposed by Duquesne Light, is consistent with PECO's condition-based approach to vegetation management. Therefore, PECO could support this approach.

PECO'S RESPONSE TO STAFF QUESTION NO. 2 - PECO'S PERIODIC I&M PLAN

Category	Cycle	Explanation
Poles	10 year	Inspect poles every 10 years after 12th year of service
Overhead Conductors and Cables	Distribution: 2 years	Inspection - Part of circuit patrol program
Wires	Distribution: 2 years	Inspection - Part of circuit patrol program
Transformers	Network: 1 year	Inspection - Part of network I&M
	Underground: 6 years	Inspection - Part of manhole inspection program
	Padmounted: 5 years	Inspection - Part of Underground Residential Development (URD) inspection Program
	Aerial: 2 years	Inspection - Part of circuit patrol program
	Network and Motor Operated: 1 year	Inspection - Part of network program or of recloser program

Switching Devices	Underground: 3 years	Inspection - Part of manhole inspection program
	Padmounted: 5 years	Inspection - Part of URD inspection Program
	Aerial: 2 years	Inspection - Part of circuit patrol program
Protective Devices	Recloser - 3 phase: 2 & 4 years	Inspection: 2 years as part of circuit patrol program. Testing: oil insulated reclosers are tested every 2 years; vacuum reclosers are tested every 4 years.
	Recloser - 1 phase: 2 years	Inspection - Part of circuit patrol program
	Aerial fuses: 2 years	Inspection - Part of circuit patrol program
	Network devices: 1 year	Inspection - Part of network program
	Underground Oil Fuses: 3 years	Inspection - Part of manhole inspection program
Regulators	2 years	Inspection - Distribution line regulators
Capacitors	2 & 4 years	Inspection - Capacitors with control switches: 2 years. Capacitors without control switches: 4 years.

Substations	Various	The Substation Inspection and Maintenance program defines maintenance requirements on an equipment type basis. Each equipment type has maintenance tasks assigned which are intended to identify, prevent or mitigate failure modes specific to the component family. This program encompasses a complex set of tasks based on the component function, interrupting medium, MVA (mega volt-amperes) rating, service condition, criticality and other factors. To illustrate this complexity a generic example of circuit breaker maintenance is provided below. Maintenance tasks and frequencies are defined for the following circuit Breaker types. Vacuum 4-34 kV, Air Magnetic, 4-12 kV, Oil, 4-13 kV, Oil, 34 kV and Above, Air Blast 66 kV and Above, Single Pressure Puffer, 2 Pressure SF6, Circuit Switcher, H-type Oil – H2O 13 kV, Air Blast 13 kV. The task definition and frequencies differ for each of the above Breaker Types based on the failure modes specific to each (i.e., they all fail in different ways at different frequencies and therefore require different tasks be performed at specific intervals). PECO utilizes a living program such that as new failure modes are identified and experience dictates; the maintenance task definitions or frequencies are modified.
Substations	Various	In general, there are 4 types of tasks with varying frequencies and definitions. 1. This inspection approximates real-time condition monitoring that can detect developing problems and degradation, and provides condition data used to initiate corrective actions. Data collected is trended and analyzed within our computerized Equipment health system. This system generates alerts or condition based corrective maintenance. Frequency 5 weeks 2. Predictive or Diagnostic in-service inspections include thermography and oil quality sampling. Typical frequencies are 6 months to 1 year. 3. Operation, functional testing, Lubrication, Detailed inspections and Diagnostic testing tasks are indicated to ensure proper operation, replace wearable components such as filters and lubricants and identify the need for more intrusive internal component failures. Frequencies vary from 3 years to 6 years. 4. Internal intrusive maintenance is performed on a subset of the circuit breaker population on a time directed or condition directed basis. Frequency varies between 6 and 18 years. It is important to note that not all tasks identified above can be applied to all components. For example you cannot test the oil of an air magnetic breaker, since there is no oil to test.

PECO'S RESPONSE TO STAFF'S QUESTIONS NOS. 3-4 - PECO'S I&M INTERVALS

Maintenance Items

Subject	PUC Proposal	Current PECO Practice	Estimated Annual Incremental Cost
1) Vegetation Management	Distribution Cycle of 4 Years.	Distribution Cycle of 5 Years with mid-cycle trimming.	$ 5,000,000
	Transmission Cycle of 5 Years.	PECO already meets the PUC proposal.	$ -
2) Pole Inspections	Poles inspected every 10 years.	Poles inspected every 10 years after 12th year.	$ -
3) Overhead Line Inspection	Transmission Lines inspected aerially twice per year (spring and fall).	Lines inspected aerially once per year during the summer to get the best observation of tree conditions.	$ 140,000
	Transmission Lines inspected on foot every 2 years.	Ground patrol (vehicle or foot patrol as necessary) follow-up to annual aerial inspection for areas not accessible to helicopter	$ 477,750
	Distribution Lines inspected on foot every year. Overhead transformers visually inspected annually as part of circuit inspection.	Ground patrol inspection of distribution lines using thermography is performed every 2 years. Inspected as part of 2 year distribution line inspection and includes thermography.	$ 3,435,000
	Padmount transformers inspected every 2 years.	Padmounted transformers inspected every 5 years.	$ 750,000
	Underground transformers inspected every 2 years.	Underground equipment inspected every 5 years.	$ 417,000
	Reclosers inspected and tested every year.	MOS reclosers are inspected and tested every year. Oil reclosers are inspected and tested every 2 years. Vacuum reclosers are inspected and tested every 4 years.	$ 335,000
4) Substation Inspections	Substation equipment, structures, hardware inspected monthly.	Inspections every 5 weeks.	$ 201,500
		Total additional annual cost to implement PUC proposals	**$ 10,756,250**

PECO's RESPONSE TO STAFF'S I&M QUESTION NO. 6
AFL-CIO PROJECTED COSTS

Category	Incremental Costs	Explanation
(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.		
(2) Pole inspections. Distribution poles shall be ~~visually~~ inspected every 10 years. 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.	$35,000	Incremental cost is for additional inspections for newer poles. No cost is provided for the corrective maintenance portion.
(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.	$140,000	Number already provided, no additional requirement. No cost is provided for the corrective maintenance portion.
(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.	$3,435,000	Number already provided, no additional requirement
(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.	$1,167,000	Number already provided, no additional requirement
(v) Reclosers in the distribution system shall be inspected and tested at least once per year.	$335,000	Number already provided, no additional requirement
(vi) The integrity of transmission towers shall be inspected and tested at least once every 25 years.	unknown	No program is place, unknown financial impact

PECO's RESPONSE TO STAFF'S I&M QUESTION NO. 6
AFL-CIO PROJECTED COSTS

Category	Incremental Costs	Explanation
(4) Substation inspections. Substation equipment, structures and hardware shall be inspected monthly. 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.	$9,000,000	Maintenance tasks and frequencies are defined for the following circuit Breaker types. Vacuum 4-34 kV, Air Magnetic, 4-12 kV, Oil, 4-13 kV, Oil, 34 kV and Above, Air Blast 66 kV and Above, Single Pressure Puffer, 2 Pressure SF6, Circuit Switcher, H-type Oil – H2O 13 kV, Air Blast 13 kV. The task definition and frequencies differ for each of the above Breaker Types based on the failure modes specific to each i.e. they all fail in different ways at different frequencies and therefore require different tasks be performed at specific intervals. We utilize a living program such that as new failure modes are identified and experience dictates; the maintenance tasks definitions or frequencies are modified. In general, there are 4 types of tasks with varying frequencies and definitions. 1. This inspection approximates real-time condition monitoring that can detect developing problems and degradation, and provides condition data used to initiate corrective actions. Data collected is trended and analyzed within our computerized Equipment health system. This system generates alerts or condition based corrective maintena Frequency 5 weeks 2. Predictive or Diagnostic in-service inspections include thermography and oil quality sampling. Typical frequ are 6 months to 1 year. 3. Operation, functional testing, Lubrication, Detailed inspections and Diagnostic testing tasks are indicated to proper operation, replace wearable components such as filters and lubricants and identify the need for more i internal component failures. Frequencies vary from 3 years to 6 years. 4. Internal intrusive maintenance is performed on a subset of the circuit breaker population on a time directed directed basis. Frequency varies between 6 and 18 years. It is important to note that not all tasks identified above can be applied to all components. For example you cannot test the oil of an air magnetic breaker, since there is no oil to test.
(5) Other inspection requirements.		
(i) Group-operated line switches shall be inspected and tested annually.	unknown	
(ii) Relays shall be inspected and tested every two years.	$2,040,000	Transmission relays are currently required by PJM to be completed every 4yrs. Distribution relays are performed every 6 years. Incremental Cost would be to double transmission program and triple distribution program.
(iii) Sectionalisers shall be inspected and tested every two years.	$ -	Sectionalizers part of the recloser program
(iv) Vacuum switches shall be inspected and tested every two years.	NA	
(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.	$ -	All underground vaults part of manhole program
	$16,152,000	

PECO'S RESPONSE TO STAFF'S I&M QUESTION NO. 8.
OCA PROJECTED COSTS

Category	Incremental Costs	Explanation
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.		
(2) Pole inspections and repair. Distribution poles shall undergo a detailed inspection every 10 years that includes 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 shall be replaced within 60 days.	$35,000	Incremental cost is for additional inspections for newer poles. No cost is provided for the corrective maintenance portion.
(3) Overhead line inspections and repair.		
(i) Transmission lines and all attached equipment shall be inspected aerially twice per year in the spring and fall. Transmission lines and all attached equipment shall be inspected on foot every 2 years and shall include infrared scanning. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced within 30 days from discovery.	$617,750	Incremental cost is for additional inspection requirements. No cost is provided for the corrective maintenance portion.
(ii)Distribution lines and all attached equipment shall be inspected by foot patrol a minimum of once per year and shall undergo a detailed inspection every 5 years that includes infrared scanning. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery.	$3,435,000	Incremental cost is for additional inspection requirements. It is unclear what constitutes a 'detailed inspection' and therefore this item has no cost adder. No cost is provided for the corrective maintenance portion.
(iii)Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection and the load on the transformer shall be calculated at least once 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.	unknown	The circuit patrol cost is included in (ii), and this would include visual inspection of overhead distribution transformers. PECO currently does not have a transformer load management program and therefore this item has no cost adder. No cost is provided for the corrective maintenance portion.
(iv)Above-ground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle and the load on the transformer shall be calculated at least once 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.	$1,167,000	Number already provided for increased periodicity PECO currently does not have a transformer load management program and therefore this item has no cost adder. No cost is provided for the corrective maintenance portion.

Category	Incremental Costs	Explanation
(v)Reclosers shall be inspected and tested at least once per year. If problems are found that affect the integrity of the equipment, they shall be repaired or replaced within 30 days from discovery.	$335,000	Number already provided No cost is provided for the corrective maintenance portion.
(vi) Other Critical Facilities shall be tested and inspected either annually ore 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.	unknown	Poles, reclosers, and certain primary network equipment is tested - PECO has no other program to test distribution equipment therefore no additional costs are available. No cost is provided for the corrective maintenance portion.
(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.	$9,201,500	Increase costs for yearly circuit breaker operational testing, 4yr comprehensive inspection and Monthly inspection. The Substation Inspection and Maintenance program defines maintenance requirements on an equipment type basis. Each equipment type has maintenance tasks assigned which are intended to identify, prevent or mitigate failure modes specific to the component family. This program encompasses a complex set of tasks based on the component function, interrupting medium, MVA rating, service condition, criticality and other factors. To illustrate this complexity a generic example of circuit breaker maintenance is provided below. Maintenance tasks and frequencies are defined for the following circuit Breaker types. Vacuum 4-34 kV, Air Magnetic, 4-12 kV, Oil, 4-13 kV, Oil, 34 kV and Above, Air Blast 66 kV and Above, Single Pressure Puffer, 2 Pressure SF6, Circuit Switcher, H-type Oil – H2O 13 kV, Air Blast 13 kV. The task definition and frequencies differ for each of the above Breaker Types based on the failure modes specific to each i.e. they all fail in different ways at different frequencies and therefore require different tasks be performed at specific intervals. We utilize a living program such that as new failure modes are identified and experience dictates; the maintenance tasks definitions or frequencies are modified.

PECO'S RESPONSE TO STAFF'S I&M QUESTION NO. 8.
OCA PROJECTED COSTS

Category	Incremental Costs	Explanation
Substation continued		In general, there are 4 types of tasks with varying frequencies and definitions. 1. This inspection approximates real-time condition monitoring that can detect developing problems and degradation, and provides condition data used to initiate corrective actions. Data collected is trended and analyzed within our computerized Equipment health system. This system generates alerts or condition based corrective maintenance. Frequency 5 weeks 2. Predictive or Diagnostic in-service inspections include thermography and oil quality sampling. Typical frequencies are 6 months to 1 year. 3. Operation, functional testing, Lubrication, Detailed inspections and Diagnostic testing tasks are indicated to ensure proper operation, replace wearable components such as filters and lubricants and identify the need for more intrusive internal component failures. Frequencies vary from 3 years to 6 years. 4. Internal intrusive maintenance is performed on a subset of the circuit breaker population on a time directed or condition directed basis. Frequency varies between 6 and 18 years. It is important to note that not all tasks identified above can be applied to all components. For example you cannot test the oil of an air magnetic breaker, since there is no oil to test.
	$14,791,250	

Orange & Rockland
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(845) 577-3341

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390 West Route 59
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www.oru.com

February 21, 2007

Honorable James J. McNulty
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Information Request Regarding Inspection, Maintenance and Repair Standards.

Dear Secretary McNulty: L-00040167

Please find attached Pike Count Light and Power's (Pike) response to Elizabeth Barnes' e-mail dated Tuesday, January 23, 2007.

Very truly yours,

Timothy Garvin

Timothy T. Garvin
Manager
Performance & Operational Engineering

TTG/dlp

Enclosure

Electronic Copy to:

Elizabeth Barnes
Pennsylvania Public Utility Commission
ebarnes@state.pa.us

Please provide Commission staff with your current policies regarding what efforts are being made to reduce the number and duration of outages due to off-right-of-way vegetation. Please be as detailed as possible and include any written policies or other directives to employees and contractors on how the policy is to be implemented.

Pike Light and Power has no stated or written policy pertaining to Off-ROW vegetation. However, we do deal with off-ROW vegetation by three separate processes.

- During the normal vegetation maintenance activities, when off-ROW vegetation is found and is of problematic condition, efforts are made to notify the owner (customer/municipality/County/State) looking for authorization and remedial assistance.
- Notice of Off-ROW hazard vegetation may also come from customers through our customer service department for investigation and remediation. This work is turned over to the local Division Engineer, and then to the vegetation management department for investigation and remediation.
- Off-ROW vegetation problems may also be identified through the Circuit Ownership Program (C.O.P.) line patrols. C.O.P. patrols identify several line conditions that my impact reliability, including vegetation conditions. This work is turned over to the local Division Engineer, and then to the vegetation management department for investigation and remediation.

With regard to all information previously provided to the Commission describing your company's current inspection, maintenance and repair standards, Please provide Commission staff with the inspection, maintenance and repair standards existing in 1990, 1995, and 2000. A comparison against the proposed regulations minimum standards in a table format is preferable.

Inspection and Maintenance Standards at Pike County Light and Power Company					
Device	**Proposed Standards**	**Currently**	**2000**	**1995**	**1990**
Substations -Visual Inspection	Monthly	Monthly	Same	Same	Same
Vegetation Management					
Transmission	5 Years	N/A	N/A	N/A	N/A
Distribution	4 Years	3 Years	Same	Same	Same
Padmount Transformers	Every 2 Years	None	Same	Same	Same
Poles	10 Years	None	Same	Same	Same
Transmission Line Inspections					
Aerial	Semi-Annual	N/A	N/A	N/A	N/A
Foot Patrol	Every 2 Years	N/A	N/A	N/A	N/A
Distribution Line Foot Patrol	Annual	No Foot Patrol. 3-Phase lines, Annual Infrared Inspection. 1,2-Phase lines, 3-Year Infrared Inspection.	Same	Same	Same
	Repair within 30 days	No Standard	Same	Same	Same
O/H Transformers	Annual	3-Phase lines, Annual Infrared Inspection. 1,2-Phase lines, 3-Year Infrared Inspection.	Same	Same	Same
Reclosers	Inspect and Test Annual	Visual Inspection Quarterly, Tested Semi-Annual	Same	Same	Same

To the extent any of the outage information/statistics you have provided in documents filed with the commission in this rulemaking reflects only frequency or only duration (or is unclear whether it is based on one or the other), please provide the same information addressing both frequency and duration. For example, if a filing states that 1% of customer outage incidents are substation related, please provide the percentage by duration of substation outage minutes to total outage minutes.

We are not aware of any instances where information/statistics filed with the commission in this rulemaking, reflected only Frequency or Duration.

MWN.

McNees Wallace & Nurick LLC
attorneys at law

2007 FEB 22 PM 3:16

PAMELA C. POLACEK
DIRECT DIAL: (717) 237-5368
E-MAIL ADDRESS: PPOLACEK@MWN.COM

PA P.U.C.

February 21, 2007

VIA HAND DELIVERY

James J. McNulty, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street – 2nd Floor
Harrisburg, PA 17120

RE: **Wellsboro Electric Company Responses for January 22, 2007, Technical Conference on Proposed Regulations For Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection and Maintenance Standards for Electric Distribution Companies; Docket No. L-00040167**

Dear Secretary McNulty:

Enclosed is Wellsboro Electric Company's ("Wellsboro") response to the additional information requested during the January 22, 2007, Technical Conference concerning the above-referenced proceeding.

Please date stamp the extra copy of this transmittal letter and kindly return it to our messenger for our filing purposes. Thank you.

RECEIVED
2007 FEB 21 PM 4:02
PA PUC
SECRETARY'S BUREAU

Very truly yours,

McNEES WALLACE & NURICK LLC

By Pamela C. Polacek
Pamela C. Polacek

Counsel to Wellsboro Electric Company

PCP/nk
Enclosures
c: Elizabeth Barnes, Esq. (via E-mail)

29

Wellsboro Electric Company
33 Austin St.
Wellsboro, PA 16901
570-724-3516

Additional Information Requested at January 22, 2007, Technical Conference Regarding Proposed I&M Standards; Docket No. ~~R-00040167~~ L-00040167

1. Please provide Commission staff with your current policies regarding what efforts are being made to reduce the number and duration of outages due to off-right-of-way vegetation.

Wellsboro Electric supplies right-of-way contractors with a line specification manual, which includes a paragraph titled DANGER TIMBER. The paragraph states: "Danger timber is defined is defined as any dead, diseased, cracked, stressed, and heavily leaning tree tall enough to strike the conductors if fell towards the line. Likewise, remove all dangerous leads/limbs off healthy trees that could hit the line if they broke off. Cut stumps flush at a height no greater than 3". All contractors when bidding circuit work must identify Danger Timber, report it to Company and attempt to obtain permission to get it removed. When our employees discover Danger Timber either during normal day-to-day work activities or scheduled line inspections, the employees must radio the office, where a tree service order is generated and forwarded to the crew chief for action. Wellsboro Electric employees find a good share of Danger Timber in the normal course of a year. A more significant problem related to off right of way trees is that many of the trees that come down during storms are good, healthy trees that Wellsboro's contractors or employees would not have identified.

2. With regard to all information previously provided to the Commission describing your company's current inspection, maintenance and repair standards, please provide Commission staff with the inspection, maintenance and repair standards existing in 1990, 1995, and 2000. A comparison against the proposed regulations minimum standards in a table format if preferable.

Ownership and management of Wellsboro Electric changed in 1995. The Company does not have any records or formal I&M Manuals prior to 1995. See the information on Attachment A for 1995, 2000, current and proposed intervals.

3. To the extent any of the outage information/statistics you have provided in documents with the commission in this rulemaking reflects only frequency or only duration (or is unclear whether it is based on one of the other) please provide the same information addressing both frequency and duration. For example, if filing states 1% of customer outage incidents are substation related, please provide the percentage by duration of substation outage minutes to total outage minutes.

See Attachment B.

Wellsboro Electric Company
Current Inspection & Maintenance Intervals
Attachment A

	1990	1995	2000	Current	PUC Proposed
Right-Of-Way Program		12	8	8	4
Pole Inspections		12	10	10	10
Transmission Inspections		N/A	N/A	N/A	N/A
Overhead Transformer Inspection		5	5	5	Annual
Pad-Mount Transformer Inspection		5	5	5	2 Year
Distribution Line Inspection		5	5	3	Annual
OCR Testing or sooner based on number of operations currently 100 operations		6	6	5	Annual
Substation Inspection		Bi-Monthly	Monthly	Monthly	Monthly

WEC0 Current I&M Intervals

Wellsboro Electric Company
Outage Data for 2006
Attachment B

Outage Cause	Percentage of Outages	Outage Cause	Percentage by Customer Minutes
Animals	25.30%	Animals	8.71%
Vehicles	2.30%	Vehicles	9.73%
Decay	1.20%	Decay	0.03%
Electrical Overload	1.20%	Electrical Overload	0.43%
Equipment Failure	20.90%	Equipment Failure	15.29%
Lightning	7.90%	Lightning	14.29%
Rain	0.30%	Rain	0.12%
Trees	20.10%	Trees	40.54%
Unknown Cause	15.50%	Unknown	5.82%
Wind	5%	Wind	4.64%
Customer Caused	0.30%	Customer Caused	0.41%
	100.00%		100.00%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Proposed Rulemaking for Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection and Maintenance Standards for the Electric Distribution Companies	:	**Docket No. L-00040167**

PECO ENERGY COMPANY'S RESPONSES
<u>TO STAFF'S FOLLOW-UP DATA REQUESTS</u>

PECO Energy Company ("PECO") hereby responds to Staff's follow-up data requests to the electric distribution companies that participated in the Commission's January 22, 2007 Technical Conference in this docket.

<u>QUESTION NO. 1</u>

Please provide Commission staff with your current policies regarding what efforts are being made to reduce the number and duration of outages due to off-right-of-way vegetation. Please be as detailed as possible and include any written policies or other directives to employees and contractors on how the policy is to be implemented.

<u>PECO'S RESPONSE TO QUESTION NO. 1</u>

Two of PECO's vegetation management programs regularly have an effect on off-right-of-way trees: (1) in an indirect way, PECO's normal, on-right-of-way trimming activities also affect trees that are located off-right-of-way, and (2) PECO's hazard tree program has a direct effect on off-right-of-way trees.

In its normal, on-right-of-way trimming activities, PECO utilizes a trimming method in which, in many situations, trimming does not end precisely at the edge of right-of-way. For example, if a distribution line has a 10-foot right-of-way on each side of the line, and a tree is located 15 feet from the edge of the line, PECO would obviously trim at least to the 10-foot clearance. However, it is better for the health of the tree, and for subsequent growth patterns of the tree, to trim each branch back to its point of origin on a larger branch, rather than leaving a stub branch cut off at the edge of right-of-way. Therefore, wherever its easements and other property rights allow it to extend the trimming off-right-of-way to make the healthier cut, or wherever PECO can negotiate such rights with a landowner during the trimming, the cuts are made to the branches' points of origin, even if they are well beyond the edge of right-of-way.

This practice is normally thought of as simply being an integral part of the on-right-of-way trimming, and in fact PECO does not keep separate budget or programmatic data for the normal cycle work that extends beyond the edge of right-of-way. However, PECO's experience is that, over the 12,000+ circuit miles on its system, over each trimming cycle it trims tens of thousand of trees some distance beyond the mere edge of right-of-way. PECO believes that this portion of its normal trimming cycle has a significant positive effect on reliability.

PECO's hazard tree program has a direct effect on off-right-of-way trees. "Hazard trees" are defined as dead or declining trees which are located such that, if they fall, they would have significant chance of falling on a PECO energy facility. PECO has a hazard tree removal procedure, a copy of which is attached (please note that the document is Confidential) that focuses on two mitigative efforts: (a) informing landowners that PECO has observed a dead or dying tree, so that the landowner can take mitigative action, and (b) in some circumstances, removing the hazard tree itself.

For removals of hazard trees (or hazard limbs) that take less than two hours of work, PECO absorbs that work into its Management Source Substation Projects (that is, into its routine trimming). No separate budgets or data are kept on the number of trees included in this program, which may include both on- and off-right-of-way trees.

For removal of hazard trees (or hazard limbs) that take more than two hours of work, the work is separately tracked as the Hazard Tree Removal Program. For 2001-2005, the number of trees removed through this separate program was:

2001	2002	2003	2004	2005
787	1091	734	425	434

A significant portion, but not all, of these trees were off-right-of-way.

The scope of this program is constrained by the limited authority PECO has to trim or remove trees that are outside of its rights-of-way. (Off-right-of-way trees are, by definition, generally located outside of the area in which PECO has obtained property rights allowing it to trim or remove the trees.) In fact, in many cases in which PECO has determined that off right-of-way trees were a hazard to its lines, the property owner opposed PECO's trimming or removal efforts, in some cases requiring multi-month legal action to remove just a few trees.

In these situations, PECO has limited options. PECO can trim or remove the off right-of-way tree(s) over the owner's objection, a course that involves the risk of legal action. PECO can alternatively seek to purchase property rights from the owner that would permit tree trimming or removal by PECO. However, this option is often prohibitively expensive and time consuming, and is only available when the owner is willing to sell its property rights.

A third alternative is to pursue condemnation. But this option is also time consuming and involves significant legal expense. In addition, utility rights of condemnation are limited – for example, a utility cannot condemn within 100 meters of a residence.

Finally, PECO can rely upon its tariff rule 10.9, Aerial Line Clearance, to obtain off-right-way clearance that conforms with the National Electrical Safety Code ("NESC").[1] As with the prior alternatives, use of this approach can involve lengthy legal actions. In addition, most off-right-of-way trees do not implicate the NESC; thus, the tariff approach does not provide a tool for seeking the trimming or removal of such trees.

The result of these various constraints is that it is very difficult for a utility to establish an aggressive program for trimming and removals off its rights-of-way and especially for healthy trees outside the rights-of-way. Simply put, requiring a utility plan to include a program for off-right-of-way vegetation management would impose a requirement on EDCs to submit plans for activities that are often outside of their immediate authority and control. Thus, while PECO maintains an active Hazard Tree Removal Program, the scope of that program is limited by the constraints noted above.

In establishing its off-right-of-way program, PECO is cognizant of statistics that approximately 80% of tree-related outages are caused by trees located off the right-of-way. PECO believes that there are two key issues to be kept in mind when reviewing this statistic.

First is whether this measure is a meaningful metric for determining the success of a vegetation management program. PECO's experience is that it is not a meaningful metric. Changes to the metric of "% of outages caused by trees off right-of-way" are primarily driven by the relative success or failure of the utility's <u>on</u>-right-of-way program. For example, if a utility has 100 tree-related outages -- 50 caused by on-right-of-way trees and 50 caused by off-right-of-way trees -- and then implements an on-right-of-way program that eliminates most (for this

[1] PECO's Tariff Rule 10.9 – Aerial Line Clearance – states that: "In accordance with the requirements set forth in the National Electric Safety Code, the Company shall have the right to trim, remove, or separate trees, vegetation or any structures therein which, in the opinion of the Company, interfere with its aerial conductors, such that they may pose a threat to public safety or system reliability."

example, 38) of the on-right-of-way outages but has no effect on off-right-of-way outages, that change alone will cause the percentage of outages caused by off-right-of-way trees to move from 50% to 80% (50 off-right-of-way outages out of 62 total outages = 80% off-right-of-way). This can also be true even if there is a successful off-right-of-way program. Continuing on the prior example, a utility that successfully eliminated 42 of its on-right-of-way outages and 20 of its off right-of-way outages would still have 80% of its outages due to off-right-of-way trees, even though it was running successful programs both on and off right-of-way (30 off-right-of-way outages out of 38 total outages = 80% off-right-of-way).

For these reasons, PECO does not find this comparative statistic to be a useful metric in evaluating the success of its off-right-of-way program. Instead, PECO looks to the opportunities that are available (or which are not available for legal or financial reasons, as noted above) for off-right-of-way programs and attempts to access those opportunities. It then measures the success of this program as a component of its overall program by use of system-wide reliability metrics.

The second issue is whether one can meaningfully identify the off-right-of-way trees that will cause future reliability problems and do something to address those trees. Obviously, trees that can be visually identified as dead or dying trees form a higher risk subset and programs, such as the PECO Hazard Tree Program, which are targeted to those known hazardous trees, can have a meaningful effect on outages. The remaining trees, however, appear to be healthy, and it is some subset of the healthy-appearing trees that will cause the outages, either because they are in fact healthy but are still blown into the utility facilities during a storm or because they are in ill-health that cannot be detected through visual inspection. Controlling outages from this subset of trees has been a very difficult exercise for all utilities. Of the large "healthy tree subset", it is not possible to identify which individual trees will ultimately cause reliability problems and focus resources on those trees; nor is it possible to remove all trees within a designated zone outside of the right-of-way. Design of off right-of-way programs must take this issue into consideration as well.

QUESTION NO. 2

With regard to all information previously provided to the Commission describing your company's current inspection, maintenance and repair standards, please provide Commission staff with the inspection, maintenance and repair standards existing in 1990, 1995, and 2000. A comparison against the proposed regulations' minimum standards in a table format is preferable.

PECO'S RESPONSE TO QUESTION NO. 2

Please see the attached spreadsheet labeled "PECO's Response to Staff's Follow-up Data Request No. 2."

QUESTION NO. 3

To the extent any of the outage information/statistics you have provided in documents filed with the commission in this rulemaking reflects only frequency or only duration (or is unclear whether it is based on one or the other), please provide the same information addressing both frequency and duration. For example, if a filing states that 1% of customer outage incidents are substation related, please provide the percentage by duration of substation outage minutes to total outage minutes.

PECO'S RESPONSE TO QUESTION NO. 3

PECO did not provide information or statistics in this rulemaking that fall within the scope of this request.

Respectfully submitted,

Anthony E. Gay, Esquire
Counsel for PECO Energy Company
Exelon Business Services Company
2301 Market Street/S23-1
Philadelphia, PA 19103
Telephone: 215.841.4635
Facsimile: 215.568.3389

Dated: February 21, 2007

Anthony.E.Gay@Exeloncorp.com

FUNCTIONAL AREA													
AD	AM	CM	CS	EA	EN	EP	EX	FI	FM	GO	HR	IT	OP
PC	QA	RE	SA	SM	TQ	VM	WM						
						X							

Hazard Tree Identification and Prioritization Procedure

1 PURPOSE

1.1 This procedure establishes the methodology that shall be applied to the Vegetation Management Hazard Tree Identification and Prioritization Program. This procedure applies to hazard trees, volunteer trees, incompatible trees and brush. This procedure provides instructions to identify, prioritize and determine which hazard trees shall be targeted for removal. It provides instruction for documentation and reporting of the Hazard Tree Program.

1.2 Section 8 has been divided into the following subsections:

Subsection	Title	Page
8.1	Identification	3
8.2	Prioritization	3
8.3	Hazardous Tree Removal	4

2 TERMS AND DEFINITIONS

2.1 ATE - Asplundh Tree Expert Company

2.2 WTS – Wright Tree Service

2.3 Brush – dense, low-growing woody vegetation that will potentially grow into aerial facilities at some point in the future.

2.4 General Foreman (GF) - in charge of the screener and reports directly to the VMPL

2.5 Hazard Tree - is one posing an immediate threat to EED aerial electrical facilities. The term hazard may refer to an entire tree, or any part thereof.

2.6 Incompatible Species - is defined by re-growth habits that are so fast as to make trimming for line clearance impracticable.

2.7 Screener - the field specialist who identifies and seeks permission for tree removals.

2.8 Vegetation Management Project Leader (VMPL) - supervises and coordinates the program.

2.9 Vegetation Management -Report Form (VMRF) - used to provide detailed information about hazard trees - Scantron Form 25772 - Hazard Tree Evaluation Form.

2.10 Volunteer Tree - self-set that is not intentionally planted or grown naturally from seed, root suckering or other means of self-propagation.

3 RESPONSIBILITIES

3.1 VEGETATION MNANAGEMENT PERSONNEL

3.1.1 Manage the hazard tree removal program to ensure the goals of the program are met.

3.2 EXELON CONTRACTOR

3.2.1 Perform tree removal in accordance with removal guidelines.

4 MATERIAL ANS SPECIAL EQUIPMENT

4.1 SPECIAL EQUIPMENT

5 SAFETY MEASURES AND ENVIRONMENTAL CONCERNS

5.1 SAFETY MEASURES

5.2 ENVIRONMENTAL CONCERS

6 PRECAUTIONS AND LIMITATIONS

6.1 PRECAUTIONS

6.1.1 None

6.2 LIMITATIONS

6.2.1 None

7 PREREQUISITES

7.1 Authorization from a VMPL is required before any trees or brush can be removed.

7.2 The contractor shall obtain written permission from the owner of any tree scheduled for removal, unless an emergency authorization has been supplied by the VMPL.

8 PROCEDURE

8.1 HAZARD TREE IDENTIFICATION PROCEDURE

8.1.1 Potential hazard trees are trees that are observed anywhere on the Exelon system property. These trees are either identified using the "Vegetation Management Additional Work Required Log" Scantron Form 58877 for future prioritization by a screener or evaluated by the GF using the Hazard Tree Evauation Scantron Form 25772. Trees can to be inventoried during the initial screening and estimating process, preventative maintenance line clearence (project trimming), midcycle screening and trimming, or quality control inspection.

8.1.2 The designated screener shall be responsible to ensure that all tree removals have the property owners permission and the express permission of the VMPL.

8.1.3 The GF in charge of removals shall ensure a herbicide application is made as a follow up to the removal, where appropriate.

8.1.4 The GF shall report all removals to the VMPL weekly.

8.1.5 The VMPL shall be responsible for budget forecasting and record maintenance.

8.2 HAZARD TREE PRIORITIZATION

8.2.1 The VMPL shall define a list of hazard trees to evaluate for removal. A screener will be designated to inspect the trees on the Additional Work Required list and prioritize each tree by following the Hazard Tree Prioritization Guidelines and Logging this information on the scantron form "Hazard Tree Prioritization Form".

8.2.2 The criteria used to prioritize the hazard trees for removal will be used to assign a point value to each hazard tree. Based on this point system, a list will be generated that will be used by the GF to determine whcich trees to remove. The criteria are based on tree species, tree condition, type of equipment and construction.

8.2.3 The GF shall report all removal locations to the VMPL bi-weekly. The VMPL shall be responsible for budget forecasting and record maintenance.

8.3 HAZARD TREE REMOVAL PROCESS

8.3.1 The VMPL shall provide the list of trees designated for removal. The screener shall inspect the circuits and identify tree removals on a VMRF.

8.3.2 The screener shall be responsible to ensure that all tree removals have the owners permission, or the express permission of the VMPL.

8.3.3 The GF shall report the completion of all hazard tree removals to the VMPL.

8.3.4 The VMPL may identify hazard trees directly to the GF for immediate removal.

8.3.5 The VMPL shall be responsible for budget forecasting and record maintenance.

9 RETURN TO NORMAL

10 DOCUMENTATION

10.1 Documentation generated during performance of this procedure shall be filed by VPML and maintained for 7 years.

11 REFERENCES

11.1 Safety and Work Practices

12 ATTACHMENTS

12.1.1 VM-ED-649-811-1; Additional Work Required Log Scantron Form 58877

12.1.2 VM-ED-649-811-2; Hazard Tree Evaluation Form Scantron Form 25772

12.1.3 VM-ED-649-811-3; Hazard Tree Prioritization Guidelines

12.1.4 VM-ED-649-811-4; Tree Species Code List

13 DEVELOPMENT HISTORY

Revision 0	Date 01/12/2005
Writer	Paul J Miceli, Vegetation Management
Reviewer(s)	Merle Turner, Vegetation Management
FAM Approver(s)	Ed Cunningham, Vegetation Management
Reason Written	This procedure was written to provide technical guidance when performing this activity.

Revision 1	Date 05/30/2005
Writer	Paul J Miceli, Vegetation Management
Reviewer(s)	Ed Cunningham, Vegetation Management, Jeff Watson, Vegetation Management
FAM Approver(s)	Doreen Masalta, Vegetation Management
Reason Written	Update format.

Revision 2	Date 04/05/2006
Writer	Paul J Miceli, Vegetation Management
Reviewer(s)	Ed Cunningham , Jeff Watson; Vegetation Management
FAM Approver(s)	Approver's Name(s): Doreen Masalta, Vegetation Management.
Reason Written	This procedure was revised to reflect current field operating procedures and eliminate duplications in Revision 1.

Revision 3	Date XX/XX/XXXX
Writer	Writer's Name (work group) [text will wrap as necessary for all lines in table]
Reviewer(s)	Reviewer's Name (work group); Reviewer's Name (work group)
FAM Approver(s)	Approver's Name(s)
Reason Written	Brief description explaining why the procedure was written or revised.

Additional Work Required Log Scantron Form 58877 – Attachment 1

VM ADDITIONAL WORK REQUIRED LOG

Today's Date: __ / __ / __ Feeder: Contractor: Reported By Crew ID # Document Number: (Office Use Only)

58877

Region: ○ CE ○ CN ○ CS ○ NE ○ NW ○ SE ○ SW

1
Address:
City/Town: Completion Date: __ / __ / __
Comments:
☐ Hazard Tree ☐ Construction Change ☐ Environmental/Established Lead ☐ Specialized Equipment ☐ Planned Outage ☐ Other

2
Address:
City/Town: Completion Date: __ / __ / __
Comments:
☐ Hazard Tree ☐ Construction Change ☐ Environmental/Established Lead ☐ Specialized Equipment ☐ Planned Outage ☐ Other

3
Address:
City/Town: Completion Date: __ / __ / __
Comments:
☐ Hazard Tree ☐ Construction Change ☐ Environmental/Established Lead ☐ Specialized Equipment ☐ Planned Outage ☐ Other

4
Address:
City/Town: Completion Date: __ / __ / __
Comments:
☐ Hazard Tree ☐ Construction Change ☐ Environmental/Established Lead ☐ Specialized Equipment ☐ Planned Outage ☐ Other

Please Fax to: Scantron Department (815) 490-2013

Coordinator ID #:

Hazard Tree Evaluation Form Scantron Form 25772 -- Attachment 2

25772

HAZARD TREE EVALUATION FORM

Company: ComEd ○ PECO ○

Submitted By ID#: Todays Date: / / Contractor: Document Number: (Office Use Only)

KeySub Project:

Feeder/Circuit:

Address

City/Town

Voltage: 4 KV ○ 12 KV ○ 13.2 KV ○ 34 KV ○

Phase Type: ○ 3 PH ○ 2 PH ○ 1 PH

Removal Permit Acquired: ○ Yes ○ No

State Roads: ○ Yes ○ No

Line Type: ○ Solid ○ Fused

Flagging Required: ○ Yes ○ No

Equip: ○ Manual ○ Lift ○ 100' Lift ○ Specialized Equip

Region:
CE ○ NW ○ DC ○
CN ○ SE ○ PH ○
CS ○ SW ○
NE ○ BM ○

Inspection Date / /

Tree Species:

Pole #:

Work Complete Date / /

DBH of Tree (inch.)

T-Quad:

Voltage Defect Failure Species Health = Total Hazard

Est. Lift Hours . Est. Manual Hours .

Actual Lift Hours . Actual Manual Hours .

○ Hazard Tree Description Make drawings in the description box as needed.

Inspector First Name Inspector Last Name

HAZARD TREE PRIORITIZATION GUIDELINES : Attachment 3

HAZARD TREE PRIORITIZATION GUIDELINES

VOLTAGE

- Fused 4kv and any secondary / service drops — *1 point*
- Fused 12kv - 13.2kv — *2 points*
- Fused 34kv — *3 points*
- Solid 4kv — *4 points*
- Solid 12kv - 13.2kv — *5 points*
- Solid 34kv — *6 points*

DEFECTS (*1 point for defect in each category – Maximum is 3 points*)

Branch Character

- Old topping wound
- Excessive weight
- Size relative to parent stem
- Presence of cracks or decay

Tree

- Poor quality of branch scaffold structure
- Past failure
- Lean
- Cabling or other support structure

TRUNK / ROOT COLLAR

- Decay, cavities, wounds, pests
- Lack of basal flair
- Lack of trunk taper
- Presence of cracks
- Included bark

FAILURE POTENTIAL

- **Low** (*1 point*) – some minor defects present, minor branch die back, minor defects or wounds. Tight planting space, moderately disturbed site.
- **Moderate** (*2 points*) – One to several moderate defects present, stem decay or cavity within safety shell limits, stem with a single crack/ check and some decay, weak union with included bark, defect affecting less than half of the tree.
- **High** (*3 points*) – multiple or significant defects present, stem decay or cavity at shell safety limits, multiple cracks/ checks which go completely through the stem, weak union with crack or decay, defect affecting greater than one half the tree's circumference with decay present, tree leaning root lifting or soil mounding, recent construction, dead or lodged branches, dead tree.

SPECIES

LOW - Not Prone to Failure (*1 point*) Hickory, Sycamore, Catalpa, Hard Maple
MODERATE – average species (*2 points*) Ash, American elm, Oaks
HIGH – weak species (3 *points*) Siberian Elm, Silver Maple, Willow, Cottonwood, Dead Tree (all species)

OVER ALL HEALTH

- Some wounds, some dead limbs present *(1 point)*
- *Signs of decline, insects /decay/major dead limbs* (*2* points)
- Tree Dead *(3 points)*

Maximum points = 18. 13 or more points indicates tree should be
Use Scantron Form 25772 to capture data.

Tree Species Code List - Attachment 4

Tree Species Code List

Tree Species	Species Code Letter	Species Code Number
BLACK OAK	BLK	6
PIN OAK	PIK	21
RED OAK	REK	25
WHITE OAK	WHK	33
WILLOW OAK	WIK	35
NORWAY MAPLE	NWM	19
RED MAPLE	REM	24
SILVER MAPLE	SIM	38
SUGAR MAPLE	SUM	27
AMERICAN ELM	AEL	1
CHINESE ELM	CEL	10
SIBERIAN ELM	SEL	41
SPRUCE	SPF	42
WHITE PINE	PIN	22
RED CEDAR	RCE	23
BLACK LOCUST	BLL	5
BLACK WALNUT	BLW	7
BLACK GUM	BUM	4
WEEPING WILLOW	WIL	31
WHITE BIRCH	BIR	32
WILD CHERRY	BLC	34
WILD GRAPE VINES	VIN	39
HACKBERRY	HAC	43
HEMLOCK	HEM	12
HICKORY	HIC	13
HONEY LOCUST	HOL	14
SWEETGUM	SWG	28
SCYCAMORE	SYC	29
SASSAFRAS	SAS	26
LOMBARDY POPLAR	POP	16
TULIP POPLAR	TUP	30
COTTONWOOD	COT	11
LINDEN/BASSWOOD	BAS	15
AILANTHUS	AIL	40
CATALPA	CAT	9
BEECH	BEE	3
MAGNOLIA	MAG	17
MULBERRY	MUL	18

ASH	ASH	2
BOX ELDER	BOX	8
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PA PUC Proposed Rulemaking on Inspection and Maintenance Standards

PECO's Response to Staff's Follow-up Data Request No. 2

Maintenance Items

Subject	PUC Proposal	PECO Current Practices	PECO 1990 Practices*	PECO 1995 Practices*	PECO 2000 Practices
1) Vegetation Management	Distribution Cycle of 4 Years.	Distribution Comprehensive Cycle of 5 Years with mid-cycle trimming and 34kV Program. Includes tree trimming, tree removals and herbicide applications.	Program was managed by the individual regions (BucksMont, DelChester & Philadelphia) within PECO. Practices not consistently applied.	Trimming only of 7,000 miles (~60% of the total system), 1998 through 2000, originally a 4-year comprehensive cycle, transitioned to 5-years in 2000. Included tree trimming, tree removals and herbicide applications.	Comprehensive Distribution Cycle of 5 Years, include tree trimming, tree removals and herbicide applications.
	Transmission Cycle of 5 Years	Transmission Cycle of 5 Years	1990-1991 span to span trimming as required. 1992 - 1996 1st 5-year Transmission Cycle.	Transmission Cycle of 5 Years	Transmission Cycle of 5 Years
2) Pole Inspections	Poles inspected every 10 years	Poles inspected every 10 years after 12th year	Variable divisional programs with 9 year target	Variable divisional programs with 9 year target	Poles inspected every 10 years
3) Overhead Line Inspection	Transmission Lines inspected aerially twice per year (spring and fall)	Lines inspected aerially once per year	Transmission Lines inspected aerially twice per year (spring and fall)	Transmission Lines inspected aerially twice per year (spring and fall)	Transmission Lines inspected aerially twice per year (spring and fall)
	Transmission Lines inspected on foot every 2 years	Annual ground patrol for areas not accessible to helicopter.	Transmission Lines inspected on foot every 3 years	Transmission Lines inspected on foot every 3 years	Transmission Lines inspected on foot every 3 years
	Distribution Lines inspected on foot every year	Ground patrol inspection of distribution lines using thermography every 2 years; includes unfused rear-property areas. Areas not accessible by vehicle inspected by foot patrol.	Variable divisional programs with 1 year target	Variable divisional programs with 1 year target	The drivable portion of aerial circuit is patrolled every year.
	Overhead transformers visually inspected annually as part of circuit inspection	Inspected as part of 2 year distribution line inspection and includes thermography	Variable divisional programs with 1 year circuit patrol target	Variable divisional programs with 1 year circuit patrol target	The drivable portion of aerial circuit is patrolled every year
	Pad-mount (Above Ground) Transformer Inspections every 2 years	Pad-mount transformers inspected every 5 years	Inspection following report of unusual condition	Inspection following report of unusual condition	5-year inspection cycle
	Underground transformers inspected every 2 years	Underground transformers inspected every 5 years.	Inspection following report of unusual condition	Inspection following report of unusual condition	Underground transformer manholes inspected every 6 years.
	Reclosers inspected and tested every year	MOS reclosers inspected and tested every year Oil reclosers inspected and tested every 2 years Non-oil reclosers inspected and tested every 4 years. Single-phase reclosers inspected as part of 2-year distribution line inspections.	Variable divisional programs with 1 year target	Variable divisional programs with 1 year target	2-year inspection cycle
4) Substation Inspections	Substation equipment, structures, hardware inspected monthly	Inspections every 5 weeks	Inspections every month	Inspections every month	Inspections every month

***PECO's pre-deregulation (pre-1998) operational structure was decentralized. Several operating divisions covering PECO's service territory were charged with administering their own maintenance goals and programs.**

UGI Utilities, Inc. – Electric Division
Docket No. L-00040167
Responses to January 22, 2007 Technical Conference Information Request

1. Summarize UGI's policy for handling out of right of way trees (i.e. "Danger Trees" Program).

Part of UGI's Line Clearance Program is to identify and act upon off right of way trees that pose a threat to its facilities ("Danger Trees"). The objective is to remove this threat before it causes damage to the delivery system facilities. By definition, danger trees have an identifiable defect such as disease, damage, physical deformity, or lean hard toward the line in a manner that poses a threat to the integrity of the line under any weather conditions.

It should be noted that many of the off right of way trees that fall on UGI's line may not be identified as danger trees. These trees look perfectly healthy but have a hidden defect such as internal decay or a compromised root system. Still others fail for no apparent reason even if examined after their failure. So even though UGI has a danger tree program in place, it is successful in identifying only a portion of the off right of way trees that eventually may fall on its line.

The identification of danger trees is done in two ways. One is UGI's Line Clearance Supervisor inspects circuits for off right-of-way danger trees during his annual line patrols. The other is all line clearance contractor personnel working on UGI's system are instructed to look for danger trees while they are performing routine maintenance trimming of a circuit. When the contractor personnel identify a danger tree, they contact UGI's Line Clearance Supervisor to make him aware of the situation.

It is the responsibility of UGI's Line Clearance Supervisor to follow-up on all identified danger trees. He first makes a thorough inspection of the danger tree to assess its condition and determine if it poses a significant risk to UGI's facilities. Assuming it does, he next determines the action that should be taken. This could be removing the portion of the tree that is at risk of falling in the direction of the line, topping the tree low enough so it won't hit the line, or removing the tree altogether.

The Line Clearance Supervisor then attempts to gain permission from the tree's owner to do the work he has determined needs to be done to correct the situation. This includes identifying the owner of the tree, scheduling a site visit with the owner, meeting with the owner at the site to explain the work desired to be done, and gaining permission from the owner to do the work. Permission is in the form of a written document signed by the owner allowing UGI to enter the property to work on the problem tree.

The Line Clearance Supervisor succeeds in most, but not all of the times, in gaining permission to work on the problem tree. But he may be denied permission to enter the owner's property altogether or may have to modify his work plan to be less aggressive to gain permission to enter the property. If he is unsuccessful in gaining permission to do the work, the process ends.

On the basis that permission has be gained to enter the property, the Line Clearance Supervisor schedules the work with the line clearance contractor and checks the quality of the work done when the job is completed.

2. Develop a matrix comparing current I&M procedures with those in 2000, 1995, and 1990.

Vegetation Management

UGI's current program for managing vegetation in the vicinity of its facilities is resultant of the evolution of its past program through the identification and evaluation of alternatives and the incremental adoption of those judged to be improvements to the then existent program. In a macro-sense, UGI's line clearance program has not changed much since 1990. Those changes that have occurred have been of an evolutionary nature making it impossible to retrospectively determine what had been changed and when. For instance, the types of herbicides to be used are evaluated as new products are brought to market and either adopted or rejected based upon perceived merits. Greater use of higher reach lift trucks are employed as they become less expensive compared to climbing to reach overhangs and high trees. Crew organization techniques are more varied to cope with the higher traffic conditions that are now more common than sixteen years ago. Refined software packages are now used to track tree crew productivity and map the work done whereas this was largely a manual process in the past. More training is required of line clearance personnel to emphasis directional trimming techniques (ANSI A300) and sensitivity to customers whose trees are being pruned. These and other numerous small, incremental changes have all led to gradual improvements in UGI's line clearance program.

It is the responsibility of the Line Clearance Supervisor to decide on which circuits should be trimmed next. This is highly dependent upon the skill and expertise of the Line Clearance Supervisor. It involves him bringing together a number of factors and applying his judgment as to the course of action that would be most effective and beneficial toward preventing tree related line outages.

The Line Clearance Supervisor starts by annually patrolling and inspecting the tree conditions on all circuits (transmission and distribution) on UGI's system. During this patrol he judges the likelihood of the tree conditions causing a circuit interruption in the coming year. He has to take into account a number of variables when making this judgment. A major consideration is the tree conditions relative to the type of line construction used along the various line segments. The type of line construction is an important consideration because certain types of line construction are more susceptible to tree related outages than others. Tree species, location to the trees relative to the circuit, tree density, right of way width, and clearance obtainable are also considered. He looks for danger trees during this patrol. In addition, he keeps track of the annual tree related interruptions by circuit and when the circuit was last trimmed. He consults the construction schedule to learn where any major circuit rebuild projects are planned. All things considered however, the main determining factor is the results of the visual inspection.

From this information, the Line Clearance Supervisor prioritizes the circuits as most need of vegetation maintenance and where the most benefit will be derived from it. He then schedules work accordingly. Once the work is scheduled, the Line Clearance Supervisor utilizes an Integrated Vegetation Management approach to prescribe the best vegetation maintenance technique or techniques to be used on a particular circuit or line segment. Listed below are various vegetation maintenance techniques used on UGI's system. Any one or all of these techniques may be used on any given circuit.

- Tree Pruning (crown reduction, side pruning).
- Tree Removal (on r/w, off r/w)
- Reclearing/Brushcutting (hand cut, mow).
- Herbicide Application (high volume stem foliar, low volume basal, ultra low volume with Thinvert, stump treatment).

While the maintenance work is being performed and upon it being completed, the Line Clearance Supervisor inspects the circuit or feeder to assure that quality work was performed and line clearance specifications were followed.

UGI Utilities, Inc. – Electric Division
Docket No. L-00040167
Responses to January 22, 2007 Technical Conference Information Request

Substations

The inspection and maintenance comparison matrix for substation equipment is as follow:

Year →	1990	1995	2000	2005
Equipment ↓				
Substations				
Routine Inspections - 230kV	Semi-Monthly	Semi-Monthly	Semi-Monthly	Semi-Monthly
Routine Inspections - ≤ 69kV	Semi-Monthly	Monthly	Monthly	Monthly
Switches				
Circuit Switcher	2 Years	2 Years	2 Years	2 Years
MOAB	2 Years	2 Years	2 Years	2 Years
69kV & 230 kV Disconnects	3 Years	3 Years	3 Years	2 Years
13kV & 4 kV Disconnects	3 Years	3 Years	3 Years	5 Years
Transmission Transformers - 230kV/69kV				
External Inspection	Semi-Monthly	Semi-Monthly	Semi-Monthly	Semi-Monthly
Dissolved Gas Test	Semi-Annually	Semi-Annually	Semi-Annually	Semi-Annually
Oil Quality Analysis	Semi-Annually	Semi-Annually	Semi-Annually	Semi-Annually
Power Factor Test	2 Years	2 Years	2 Years	2 Years
Distribution Transformer - 69kV/13kV & 13kV/4kV				
External Inspection	Monthly	Monthly	Monthly	Monthly
Dissolved Gas Test	Annually	Annually	Annually	Annually
Oil Quality Analysis	Annually	Annually	Annually	Annually
Power Factor Test	5 Years	5 Years	5 Years	5 Years
Circuit Breakers - Oil/Vacuum/Air ≤ 15kV				
Internal Inspection	6 Years	6 Years	6 Years	6 Years
External Inspection	Monthly	Monthly	Monthly	Monthly
Oil Dielectric/ Hi Pot	6 /6 Years	6 /6 Years	6 /6 Years	6 /6 Years
Ductor Test	6 Years	6 Years	6 Years	6 Years
Mechanism Check	6 Years	6 Years	6 Years	6 Years
Operational Test	6 years	6 Years	6 Years	6 Years
Circuit Breakers - Oil/Gas 69kV/Gas 230 kV				
Internal Inspection	4/--/-- Years	4/--/-- Years	4/--/-- Years	4/--/-- Years
External Inspection	Monthly	Monthly	Monthly	Monthly
Oil Dielectric	4/--/-- Years	4/--/-- Years	4/--/-- Years	4/--/-- Years

Ductor Test	4/4/2 Years	4/4/2 Years	4/4/2 Years	4/4/2 Years
Mechanism Check	4/4/2 Years	4/4/2 Years	4/4/2 Years	4/4/2 Years
Power Factor Test	4/4/2 Years	4/4/2 Years	4/4/2 Years	4/4/2 Years
Motion Analysis	4/4/2 Years	4/4/2 Years	4/4/2 Years	4/4/2 Years
Batteries	Annually	Annually	Annually	Annually
Infrared Scan	Annually	Annually	Annually	Annually
Instrument Transformer				
Power Factor Test	4 Years	4 Years	4 Years	4 Years

As can be seen, inspection of substations operating at less than or equal to 69 kV was changed from semi-monthly to monthly in the 1990 – 1995 period. This followed the introduction of SCADA monitoring of these substations in the late 1980's. Prior to then these substations were unmonitored. Also but not shown is UGI does infra red inspection of its substations. Prior to 2003 infra-red inspections were done on a three year cycle using a contractor to perform this service. In 2003 UGI purchased an infra-red camera and began doing infra-red inspections on an annual basis. Based on the results of its infra-red inspection of substation disconnects, UGI changed the maintenance cycle of these devices in the 2000 – 2005 period. Note also that internal inspections and oil dielectric testing is not required on 69kV and 230kV gas circuit breakers. The oil is replaced in these units when the dielectric test results indicate deterioration. Overall maintenance cost decline as more and more of the old oil filled circuit breakers on UGI's system are replaced with modern, gas filled units.

Other technical improvements that have occurred since 1990 are the introduction of solid state relays and metering, introduction of vacuum circuit breakers, use of Hydran oil monitoring on 230/69kV transformers, introduction of fiber optic communications between substations for relay and control, video monitoring of substations, and modernization of the SCADA terminal equipment including transducers at these substations. These improvements have been introduced gradually with no distinct transition. These transitions are continuing. The older devices that the new technology devices replace will remain in service at many locations until the end of their useful service lives and will be replaced at that time. As such, there are many vintages of technology on the UGI system at any given point in time.

Lines and Line Equipment

The inspection and maintenance comparison matrix for lines and line equipment is as follows:

Year →	1990	1995	2000	2005
Equipment ↓				
Poles	I & M - 10 Years	I & M - 10 Years	I & M - 10 Years	I & M - 10 Years
Underground Facilities	I & M - 10 Years	I & M - 10 Years	I & M - 10 Years	I & M - 10 Years
Reclosers/ Sectionalizers (1)	Maintain - 5 Years/100 Operations	Maintain - 5 Years/100 Operations	Maintain - 5 Years/100 Operations	Maintain - 5 Years/100 Operations
Distribution Switches	I & M - 5 Years	I & M - 5 Years	I & M - 5 Years	I & M - 5 Years
Capacitors (2)	Inspect - Semi - Annually	Inspect - Semi - Annually	Inspect - Semi - Annually	Inspect - Semi - Annually
Voltage Regulators	Inspect - Monthly Maintain - 10 Years/100,000 Operations	Inspect - Monthly Maintain - 10 Years/100,000 Operations	Inspect - Monthly Maintain - 10 Years/100,000 Operations	Inspect - Monthly Maintain - 10 Years/100,000 Operations
Transmission Lines (2) (3)	Patrol Annually	Patrol Annually	Patrol Annually	Patrol Annually
Transmission Line Switches	I & M - Annually	I & M - Annually	I & M - Annually	Inspect - Annually Maintain - Bi - Annually
Transmission Line Towers - Painting	10 Years	10 Years	10 Years	10 Years

Notes:
(1) Electronic Reclosers are inspected quarterly.
(2) Maintenance Performed as required from results of inpections/partols.
(3) A separate patrol is made annually to assess tree conditions and other encroachments on both transmission and distribution lines.

Maintenance of 69 kV switches was changed to bi-annually in the 2000 – 2005 period to conform with the maintenance cycle of substation switches.

In the 1990 – 1995 period UGI began doing neutral testing of distribution underground lines. In the 2000 – 2005 period it began using infrared inspections of during underground inspection to locate hot spots (indication of a failing connection).

UGI has introduced new line and line equipment technologies to its system as they are brought to market by equipment suppliers and its engineers gain confidence that the equipment will perform as touted and can be deployed on the system without adversely impacting the system's reliability. This is an evolutionary process that varies manufacturer to manufacturer as they compete for a greater market share with price and the technological advantages of their products. Improvements in overhead and underground line hardware and switches have been gradual over time. This is not to say that some technological improvements are not more substantial than others. For instance, the introduction of solid dielectric insulated/vacuum interruption devices replacing oil filled devices is a major change that holds promise of improving reliability of operation and decreasing required maintenance. The change to solid state controls for reclosers, voltage regulators, and capacitors have improved their reliability of operations. But generally there are no distinct junctures marking the introduction of new technologies. UGI has adopted them and continues to adopt them on a continuing basis. And, as in substations, there are many different vintages of equipment on UGI's T&D lines. The older vintages of equipment will be replaced as they reach the end of their useful lives.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Proposed Rulemaking for Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection and Maintenance Standards for Electric Distribution Companies

Docket No. L-00040167

Response of Duquesne Light Company

I. INTRODUCTION

Duquesne Light Company ("Duquesne" or "the Company") submits the following data in response to a request in the above-captioned docket following the Pennsylvania Public Utility Commission's ("PUC" or "Commission") January 23, 2007 technical conference. Duquesne has previously participated in this docket by presenting at the above Technical Conference, and filing comments on February 4, 2005, and November 6, 2006. Duquesne incorporates any previous comments by reference. As the public comment deadline for this docket has been extended until April 16, 2007, Duquesne reserves the right to provide additional comments at a later date.

The Commission has requested the Electric Distribution Companies ("EDCs") to provide additional information on current policies regarding what efforts are being made to reduce the number and duration of outages due to off-right-of-way vegetation. The Commission has also requested details regarding the inspection, maintenance and repair standards existing in 1990, 1995, and 2000. The Commission prefers a comparison against the proposed regulations minimum standards in a table format.

II. DUQUESNE LIGHT RESPONSE

Duquesne Light addresses the Commission's question regarding off right-of-way vegetation by attaching the Company's specifications on how the Company addresses fall-ins from outside the right-of-way **(Attachment A)**.

Duquesne Light's Vegetation Management Department is taking proactive measures to address preventable interruptions through its PIT (Potential Interruption Tree) Remediation Program **(Attachment B)**. The PIT Remediation Program was initiated in 2006 to address preventable fall-in's (FI's) on the Duquesne Light system. While tree growth is predominantly addressed through periodic pruning, falling trees from outside of the maintained rights-of-way continue to be a monumental challenge. From in depth analysis of gathered tree-related outage data, notably the physical failure characteristics of involved trees, the Duquesne Vegetation Management Department developed and implemented this program in an attempt to reduce the number of FI's from both within and from outside of the maintained rights-of-way. Initially, this mid-cycle effort will focus on distribution circuits that are 3 - 4 years old since the latest Integrated Vegetation Management (IVM) effort, and on poor performing circuits. Main feeders and unprotected laterals will be reviewed for hazardous trees targeting the facilities, which will then be addressed to pro-actively avoid interruptions to our customers.

Duquesne compares the inspection, maintenance and repair standards existing in 1990, 1995, and 2000 with the proposed PUC regulations, as well as the Company's current practices in the matrix labeled as **Attachment C**.

III. CONCLUSION

Duquesne, once again, respectfully notes that the Commission's focus should be on an EDC's results rather than on specific activities within a plan. The Company fully supports the existing reliability regulations and has focused business decisions in support of them. Duquesne has established an inspection and maintenance plan designed to control costs, prioritize repairs and maintenance, and focus on reliable service. The Company has established processes to prioritize inspection and maintenance, and has achieved very positive results. Duquesne's electric distribution system consistently outperforms the Reliability Benchmarks and Standards the Commission established in 1999 and revised in 2005.

Duquesne Light appreciates this opportunity to provide additional details on the Inspection and Maintenance and Vegetation Management practices that are in place in our service territory.

Dated this 21st day of February, 2007.

Respectfully submitted,
Duquesne Light Company

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ATTACHMENT A

Duquesne Light - 2007 SPECIFICATION CHANGES:

DEFINITIONS SECTION:

Hazardous Limb/Tree – Any tree, in part or whole, with visible defects degraded to the point that it poses a potential threat upon failure, and targets the electrical facilities.

PRUNING SECTION:

For Rural-Type Rights-of-Way: In a rural-type rights-of-way situation with no overhead primary, apply the rural-type rights-of-way specification flagging the distance of five (5) feet from the nearest conductor to identify the necessary pruning along the large tree edge. Overhanging limbs from outside the five- (5) foot tree edge shall be elevated to a minimum height of fifteen (15) feet above the highest conductor selecting for strong, healthy limbs with upward growth habits of 45° or more. All hazardous limbs shall be addressed.

All elm species that require clearance pruning and would adversely impact the facilities upon death, shall be considered for removal and/or safety pruning due to the mortality of this species caused by elm yellows and Dutch Elm disease.

Pruning Requirements Specific to Urban-Type Rights-of-Way (i.e. Yards):

Clearance shall extend upward to include overhanging limbs that shall be elevated above the highest conductor selecting for strong, healthy limbs with upward growth habits of 45° or more. Hazardous limbs shall be addressed.

REMOVAL SECTION:

Contractor shall investigate all trees in, along, and behind the natural large tree edge of the rights-of-way (including a 15' wide zone on the opposite side of the road for lines adjacent to a road) for potential interruption trees targeting the Company's facilities.

Distribution and Sub transmission – A second flag shall be hung a distance of 35' from the outside conductor to create a zone (between 20' – 35') where the identification and remediation of potential interruption trees shall be addressed as part of the Work.

Transmission – A second flag shall be hung a distance of 50' from the outside conductor to create a zone (between 35' – 50') where the identification and remediation of potential interruption trees shall be addressed as part of the Work.

Potential hazard trees targeting the Company facilities shall be removed to the point where they no longer present a reliability or safety concern to such facilities.

Investigation is to include, in addition to terms presented in Section I. Definitions, dead or dying trees along or behind the natural large tree edge, or on the opposite side of the road targeting the electrical facilities shall be addressed depending on the following conditions:

- Height of tree
- Direction of prevailing winds
- Topography of the land
- Direction of the lean

ATTACHMENT B

Duquesne Light Company

RELIABILITY EXPECTATIONS FOR

VEGETATION MANAGEMENT PIT ACTIVITIES

A. Vegetation-Related Interruptions
  1. Fall-In's (FI's)
     a. Preventable – detectable defects that are visible points of failure in the scaffold of a tree or in its base with the facilities as a target
        i. Within the maintained r/w
           1) Yard trees
           2) Trees along large tree edge
        ii. Outside of the maintained r/w
           1) Trees outside of the large tree edge
     b. Non-Preventable – non-detectable defects that are not visible points of failure in the scaffold of a tree or in its base with the facilities as a target
        i. Within the maintained r/w
           1) Yard trees
           2) Trees along large tree edge
        ii. Outside of the maintained r/w
           1) Trees outside of the large tree edge

B. Revelations of VM Outage Investigations
  1. FI's - 63% of the reported tree-related interruptions are due to Fall-Ins (FI)
     a. From 0 - 30 feet of the conductor, 66% of FI's occur

C. Procedure
  1. Utilize PIT fielders to identify remedial work on circuits 3 - 4 years old since last worked. Experienced UVM professionals will primarily perform the following duties:
     a. Field review circuits and identify FI's
        i. Qualifications for PIT Remediation
           1) FI's – Top Priority; Remove or safety prune
              a. Obvious hazardous, or dead trees
     b. GPS each PIT unit and proposed fusing location by collecting a waypoint for location identification with the Garmin hand held unit.
        i. Document the waypoint number with the property owner notification details for the PIT's identified for each property.
        ii. Document the waypoint number with each proposed fusing location.
  2. Focus for PIT identification and fusing proposals will be on 23kV distribution and 23TkV sub transmission circuits.
     a. All observations will begin at the source substation working continuously through the entire circuit to the end. Focus will be primarily on main feeder and unprotected taps.

b. The highest level of scrutiny will be given to circuit sections with stacked main feeders. Single circuit main feeders will be given the next highest level of scrutiny. Main feeders appear as double lines on the circuit maps.
    i. Unfused taps will be reviewed for PIT remediation work. Unfused taps will be reviewed for vegetation concerns and for potential fusing recommendations. Taps appear as a single line on the circuit maps.
        1) If a protective fuse is recommended for a tap, the fielder will identify the proposed fusing location on the circuit map with a slashed circle with the corresponding pole number documented.

c. Fused taps will not be reviewed unless an interruption would impact > 100 customers. Fused taps appear as having an "s" inserted in the single line drawn on the circuit maps.

Reliability Problem: Reoccurring impact to SAIFI & SAIDI by Fall-In's

Charge: Reduce Fall-In's

Analysis of Vegetation-Related Interruption Data (2006; through 5/15):
Vegetation Management's year-to-date field review and assessment of tree-related interruptions indicates that 63% of the reported tree-related interruptions are due to Fall-Ins (FI) and 17% are due to Grow-Ins (GI). The FI's are further broken down into the following categories:

1. Uprooted healthy trees; no visible evidence that tree will fail (21%)
2. Unhealthy conflict trees; entire or parts of trees that are dead, dying, or diseased which fail structurally (31%)
3. Physically damaged healthy trees; isolated storm or human damage to otherwise healthy trees (11%)

Additionally, of these FI's:

1. From 0 - 20 feet of the conductors, 41% of FI's are occurring due to:
    a. Entire dead trees (33%)
    b. Decayed or diseased trees (50%)
    c. Dead branches (17%)
2. From 0 - 30 feet of the conductor, 66% of FI's occur
3. From 0 - 40 feet of the conductor, 84% of FI's occur
4. Locations of FI's are broken down into:
    a. Yard type settings (maintained lawn areas, tree lawns, etc.) = 34%
    b. 1-Sided R/W (roadside r/w) = 50%
    c. 2-Sided R/W (cross country r/w) = 16%
5. Occurrence on circuits that are aging:
    a. 6 years old (2000) = 5%
    b. 5 years old (2001) = 25%
    c. 4 years old (2002) = 32%
    d. 3 years old (2003) = 23%
    e. 2 years old (2004) = 11%
    f. ≤1 year old (2005) = 4%

Discussion:
Interpreting our data, there are obvious preventable FI's (up to 42%; includes conflict and physically damaged trees) that could potentially be identified in the field and addressed, prior to failure. Sixty-six percent of the overall FI's are occurring within 30 feet of the conductors, which is the area of common focus during scheduled maintenance efforts. First and foremost, VM inspectors take full responsibility for and are humbled by preventable failure points missed during inspections of line clearance work. Unfortunately, the detection of defects and extent of decay is not an exact science and there is an element of risk taking in the decisions that are made every day. We continue to focus on our "misses" to learn for the program's improvement. Secondly, trees are injured and die during the time between our maintenance efforts. These circuits are not generally reviewed between cycles unless there is a reliability problem and therefore, these obvious defective trees sit and await failure. In this fact alone, is our greatest opportunity for improvement with the introduction of an interim circuit/project inspection followed up with timely remedial efforts for identified FI's.

As we examine the physical location of the FI's, interestingly enough trees are failing where they can readily and frequently be seen; in front yards and along roads that are traveled daily, not in the woods. This is discouraging from the standpoint alone that our company, as a whole, has numerous people in the field every day who could be assisting in the identification of these potential interruption situations.

Proposal:
Maintain the existing cycle lengths, but initiate an interim inspection and remedial work effort targeting FI's. Emphasis should be on the 3rd year after scheduled maintenance has occurred. This would add 1,200 – 1,500 circuit miles to VM's existing work schedule annually.

The persons selected to perform the inspection work must be physically able and highly skilled in the detection of potential interruption situations involving trees. The inspection work should be separate from the remedial work efforts performed by line clearance contractors. There would be opportunity for competitive bidding of the remedial efforts and possibly incentive type contracting for the inspectors.

PA PUC Proposed Rulemaking on Inspection and Maintenance Standards

Duquesne Light - Major Items

2/21/2007

Subject	PUC Proposal	Current Practice	2000	1995	1990
1) Vegetation Management	Distribution Cycle of 4 Years	Target distribution cycle = 5 years; Actual distribution cycle = 5.63 years (Based on time period from years 2001 - 2005)	Completion year for the recovery of the entire system, both T&D (2004 - 2000). By 2000, all circuits had been gone over one time to varying degrees of thoroughness (continual improvement in specifications and supporting budgets during this time period). Cycle > 6yrs	No established cycle in existence. Formal VM program initiated in 1994.	No established cycle in existence. No formal VM program in existence. Assumption - Program consisted of random hot spotting on main feeders of 23kV only.
	Transmission Cycle of 5 Years	Target transmission cycle = 6 years; Actual transmission cycle = 7.04 years (Based on time period from years 2001 - 2005). Field conditions are evaluated during annual aerial patrols and specific work is adjusted as necessary to ensure reliability. Danger trees identified during aerial patrols are remediated after the patrol is completed.	Completion year for the recovery of the entire system, both T&D (2004 - 2000). By 2000, all circuits had been gone over one time to varying degrees of thoroughness (continual improvement in specifications and supporting budgets during this time period). Cycle > 7yrs	No established cycle in existence. Formal VM program initiated in 1994.	No established cycle in existence. No formal VM program in existence. Assumption - System hot spotted at best as needed.
2) Pole Inspections	Poles inspected every 10 years	Poles tested every 12-15 years, Visually Inspected every 5 years with Infrared	Pole Testing program had been established and implemented on a 12-15 year cycle.	Pole Testing equipment had been acquired but used only on an as-needed basis.	No formal Pole Testing program in existence. Visual inspection on a "per job" basis only.
3) Overhead Line Inspection	Underground transformers inspected every 2 years	Network transformers are inspected annually. Inspection of pad mounted transformers and of non-Network transformers is not formalized.	Network transformers were inspected annually. Inspection of pad mounted transformers and of non-Network transformers was not formalized.	Network transformers were inspected semi-annually. Inspection of pad mounted transformers and of non-Network transformers was not formalized.	Network transformers were inspected semi-annually. Inspection of pad mounted transformers and of non-Network transformers was not formalized.
	Reclosers inspected and tested every year	Our 23kV line reclosers that do not have modern self-monitoring systems are inspected every other year using proven condition-based field maintenance techniques. Our modern reclosers with self-monitoring and real-time SCADA-based alarm reporting do not get any planned maintenance, yet they are the most reliable. Our single phase 4kV reclosers are not tested. They are run to failure and replaced using corrective maintenance, much like fuses. This zero planned maintenance practice provides excellent reliability & customer satisfaction, far better than fuses.	Condition-based maintenance was implemented on 23kV SCADA-monitored reclosers on a 1 year cycle. Failure modes were examined and maintenance methods were revised to focus on components that exhibit marginal reliability. Our single phase 4kV reclosers were not tested. They are run to failure and replaced much like fuses. This practice provided excellent reliability and better customer satisfaction than fuses.	The 23kV SCADA-monitored reclosers were tested on a 1 year cycle, but maintenance methods needed improved. Our single phase 4kV reclosers were not tested. They are run to failure and replaced much like fuses. This practice provided excellent reliability and better customer satisfaction than fuses.	Condition-based maintenance was implemented on 23kV SCADA-monitored reclosers on a 1 year cycle. Our single phase 4kV reclosers were not tested. They are run to failure and replaced much like fuses. This practice provided excellent reliability and better customer satisfaction than fuses.
	Transmission Lines inspected aerially twice per year (spring and fall)	Patrols performed for Vegetation. Engineering performs inspections observing other issues. VM Patrols - Transmission lines >200kV and DLCo critical circuits aerially inspected 2x's per year (NERC); 200kV and below aerially patrolled 1x per year during late summer.	No VM aerial patrols performed.	No VM aerial patrols performed.	Assumption - No VM aerial patrols performed.
	Transmission Lines inspected on foot every 2 years	Lines inspected by foot if aerial patrol determines that closer inspection is needed or in areas that are difficult to inspect aerially. VM works transmission circuits 2 consecutive years, every 4-6 yrs depending upon the characteristics of the circuit(s) involved.	VM worked and therefore inspected vegetation on transmission circuits > every 7yrs depending upon the characteristics of the circuit(s) involved.	No established maintenance program in existence and therefore assumption is that there were no thorough transmission line inspections for vegetation-related issues. Formal VM program initiated in 1994.	Assumption - No VM foot patrols performed.
	Distribution Lines inspected on foot every year	Infrared inspection of overhead lines, equipment and connection points on a 5 year cycle. Distribution lines are also visually inspected during Pole Testing cycle and during rehabilitation of circuit jobs.	Infrared inspection of overhead lines, equipment and connection points on a 5 year cycle. Distribution lines are also visually inspected during Pole Testing cycle and during rehabilitation of circuit jobs.	No formal inspection program. Line Walkers inspected circuits on an as-needed basis.	No formal inspection program. Line Walkers inspected circuits on an as-needed basis.
	All problems found during inspections fixed within 30 days - DISTRIBUTION	Serious problems that have the potential to affect safety or power flow are generally corrected within 30 days. Lower priority problems that are discovered through inspections or condition-based maintenance are managed and corrected through rehabilitation replacements or repairs. There is no standard for timely action, since some of these are deferred to take advantage of long range capital investments.	Serious problems that have the potential to affect safety or power flow were generally corrected within 6 months. Lower priority problems that are discovered through inspections or condition-based maintenance are managed and corrected through rehabilitation replacements or repairs. There is no standard for timely action, since some of these are deferred to take advantage of long range capital investments.	Serious problems were corrected when funding and resources were available. Priority was not closely monitored or controlled. Lower priority work was sometimes not tracked or logged.	Serious problems were corrected when funding and resources were available. Priority was not closely monitored or controlled. Lower priority work was sometimes not tracked or logged.
	All problems found during inspections fixed within 30 days - TRANSMISSION	Schedule based upon severity/priority. Outages scheduled through PJM may not be granted on our timeline. Serious problems that have the potential to affect safety or power flow are generally corrected within 30 days. Lower priority problems that are discovered through inspections or condition-based maintenance are managed and corrected through rehabilitation replacements or repairs. There is no standard for timely action on lower priority issues, since some of these are deferred to take advantage of long range capital investments.	Serious problems that have the potential to affect safety or power flow were generally corrected within 6 months. Lower priority problems that are discovered through inspections or condition-based maintenance are managed and corrected through rehabilitation replacements or repairs. There is no standard for timely action on lower priority issues, since some of these are deferred to take advantage of long range capital investments.	Serious problems were corrected when funding and resources were available. Priority was not closely monitored or controlled. Lower priority work was sometimes not tracked or logged.	Serious problems were corrected when funding and resources were available. Priority was not closely monitored or controlled. Lower priority work was sometimes not tracked or logged.
	Overhead transformers visually inspected annually as part of circuit inspection	Inspected with infrared equipment on a 5- year circuit inspection cycle. Visually inspected on-the-job and during circuit rehabilitation.	Inspected with infrared equipment on a 5- year circuit inspection cycle. Visually inspected on-the-job and during circuit rehabilitation.	No formal inspection program. Line Walkers inspected circuits on an as-needed basis.	No formal inspection program. Line Walkers inspected circuits on an as-needed basis.
4) Substation Inspections	Substation equipment, structures, hardware inspected monthly	Monthly Inspections	Monthly Inspections	Monthly Inspections	Monthly Inspections

PPL Electric Utilities Corporation

Responses to Commission Questions of January 22, 2007

Questions for all Pennsylvania EDCs

1. Please provide Commission staff with your current policies regarding what efforts are being made to reduce the number and duration of outages due to off-right-of-way vegetation. Please be as detailed as possible and include any written policies or other directives to employees and contractors on how the policy is to be implemented.

   Answer: PPL Electric's distribution vegetation management specification requires contractors to remove any danger tree identified by PPL Electric's forestry professionals, including obtaining permission of the property owner for its removal. There currently are no directed initiatives towards additional tree identification or removal. However, PPL Electric is reducing the cycle times of its distribution line clearing, which will result in more frequent inspections and removals of identified off right-of-way danger trees.

2. With regard to all information previously provided to the Commission describing your company's current inspection, maintenance and repair standards, Please provide Commission staff with the inspection, maintenance and repair standards existing in 1990, 1995, and 2000. A comparison against the proposed regulations minimum standards in a table format is preferable.

   Answer: Attachment 1 provides I&M information on those programs for which PPL Electric has verifiable information. Many of the key employees who had responsibilities for PPL Electric's I&M programs in the 1990s have retired, and much of the associated documentation has been destroyed in accordance with PPL Electric's standards for document retention. Accordingly, PPL Electric has provided answers only for those areas where either key employees are still with the Company, or for which documentation exists. If neither of these sources are available, it is so indicated on the attachment.

   At the January 22, 2007 Technical Conference, both the AFL-CIO Utility Caucus and the Office of the Consumer Advocate suggested that the EDCs estimate of additional costs from the proposed I&M standards could be funded with money saved by the EDCs during the 1990-1995 time period. Attachment 2 summarizes maintenance expense for 1990, 1995 and 2005. Attachment 2 also shows the change in labor rates over the same time frame.

3. To the extent any of the outage information/statistics you have provided in documents filed with the commission in this rulemaking reflects only frequency or only duration (or is unclear whether it is based on one or the other), please provide the same information addressing both frequency and duration. For example, if a filing states that 1% of customer outage incidents are substation related, please provide the percentage by duration of substation outage minutes to total outage minutes.

Answer: On page 11 of comments filed by PPL Electric on November 6, 2006, it was reported that only 1.2% of PPL Electric's service interruptions are due to the failure of poles, arms or attachments. This corresponds to 3.1% of customer minutes.

PPL Electric Specific Questions

1. Please clarify PPL Electric's definition of "Rural" and "Urban" circuits, and indicate the number of miles in each designation.

   Answer: PPL Electric 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.

2. What % (both frequency and duration) of PPL Electric outages are due to equipment failures?

   Answer: Attachment 3 is a table showing the breakdown of equipment asset by type, as recorded using PPL Electric's reporting codes.

3. How many circuit reclosers are vacuum vs. oil? How quickly are you replacing oil with vacuum?

   Answer: As of February 2007, of the approximately 5,100 automatic circuit reclosers on PPL Electric's system, 575 are vacuum reclosers. The remainder are oil reclosers. PPL Electric's program to replace oil reclosers with vacuum reclosers is only part of its intelligent sectionalizer program or remote OCR program, as described in Attachment 4.

4. Please provide a list of the initiatives PPL Electric has undertaken to improve reliability.

   Answer: Attachment 4 provides a list of the initiatives undertaken to improve performance to levels substantially better than benchmark levels and their intended improvements.

Comparison of Proposed Regulations and PPL Electric's 1990, 1995 & 2005 Practice

NOPR	PPL Electric 1990	PPL Electric 1995	PPL Electric 2005
§57.198 (e) (1) Vegetation Management			
Transmission Cycle of 5 Years	No company-wide standard. Regions had latitude to determine cycles, circuits.	Beginning in 1995 and through 2000, there were changes to our policy, but we are uncertain which policies were adopted in 1995.	Inspect every 3 to 5 years; treat as needed based upon inspection.
Distribution Cycle of 4 Years	No company-wide standard. Regions had latitude to determine cycles, circuits.	No company-wide standard. Regions had latitude to determine cycles, circuits.	Rural: 8 year cycle. Urban: 5 year cycle.
§57.198 (e) (2) Pole Inspections			
Distribution poles inspected every 10 years	Initial inspection of SYP creosoted poles at 25 yr. Subsequent inspections vary from 1-9 years based upon result of last inspection. No "C-truss" to extend life.	Initial inspection of SYP creosoted poles at 25 yr. Subsequent inspections vary from 1-9 years based upon result of last inspection. No "C-truss" to extend life.	Initial inspection of SYP creosoted poles at 25 yr.; initial inspection of all other types at 10 yr. Subsequent inspections vary from 1-9 years based upon result of last inspection. "C-truss" to extend life where appropriate.
§57.198 (e) (3) Overhead Line Inspection			
Transmission Lines inspected aerially twice per year (spring and fall)	Uncertain	Uncertain	Annual "quick fly-over" patrol of all transmission circuits.
			Annual comprehensive aerial inspection of Susquehanna SES (nuclear) circuits. 4 year comprehensive aerial inspection of all other circuits.
Transmission Lines inspected on foot every 2 years	Uncertain	Uncertain	Transmission Lines inspected from ground every 4 years.
Distribution Lines inspected on foot every year	As required, based on circuit performance, but no organized inspection/maintenance program.	As required, based on circuit performance, but no organized inspection/maintenance program.	No fixed interval; based upon Circuit Performance Index (CPI) and analysis of actual service interruptions.
Distribution problems found during inspections that affect the integrity of the circuit to be fixed within 30 days.	Critical problems are immediately addressed. Others combined with other maintenance/repair work.	Critical problems are immediately addressed. Others combined with other maintenance/repair work.	Critical problems are immediately addressed. Others combined with other maintenance/repair work.
Transmission problems found during inspections that affect the integrity of the circuit to be fixed within 30 days.	Schedule based on severity.	Schedule based on severity.	Schedule based on severity.
Overhead transformers visually inspected annually	Uncertain	Uncertain	No fixed interval.
Pad-mount transformers inspected every 2 years.	Uncertain	Uncertain	No fixed interval.
Below ground transformers inspected every 2 years	Uncertain	Uncertain	LTN vaults inspected every 6 months.
	Uncertain	Uncertain	No fixed interval for submersible transformers.
Reclosers inspected and tested every year	6 year replacement cycle.	8 year replacement cycle.	10 year replacement cycle.
§57.198 (e) (4) Substation Inspections			
Substation equipment, structures, hardware inspected monthly	Transmission Yards: Critical Bulk Power – Weekly.	Transmission Yards: Critical Bulk Power – Weekly.	Transmission Yards: Critical Bulk Power – Weekly.
	Transmission Yards: Non-Critical - Monthly.	Transmission Yards: Non-Critical - Quarterly.	Transmission Yards: Non-Critical - Monthly.
	Distribution Yards: Non-SCADA - Monthly.	Distribution Yards: Non-SCADA - Monthly.	Distribution Yards: Non-SCADA - Monthly.
	Distribution Yards: SCADA – Monthly.	Distribution Yards: SCADA – Quarterly.	Distribution Yards: SCADA – Quarterly.

Comparison of PPL Electric's 1990, 1995 & 2005 Expense

	1990	1995	2005
Transmission and distribution overhead and underground line maintenance and substation maintenance expense. (FERC Form 1, accounts 570, 571, 572, 592, 593 & 594)	$46,600,653	$43,376,649	$66,380,689
Journeyman lineman hourly wage including benefits	$23.67	$30.89	$43.35

Note: PPL Electric cannot provide historic costs in the categories that currently are used for internal cost management and reported in quarterly and annual reports to the Commission, because these categories were not established until the late 1990s. Therefore, the costs above are provided from PPL Electric's FERC Form No. 1.

PPL Interruptions due to Equipment Failure

YEAR	Cause	COMPONENT	Trouble Cases	Percent of Trouble Cases	Customer Interruptions	Percent of Customer Interruptions	Customer Minutes	Percent of Customer Minutes
2006	Equipment Failure	OH: Lines 66kV or above	9	0.04%	50,978	2.96%	3,420,628	1.21%
2006	Equipment Failure	OH: Other Equipment - Explain	264	1.07%	12,071	0.70%	989,835	0.35%
2006	Equipment Failure	OH: Pole/Arms/Attachments	295	1.19%	67,466	3.92%	8,613,314	3.05%
2006	Equipment Failure	OH: Primary/Neutral	668	2.70%	165,923	9.63%	21,613,393	7.66%
2006	Equipment Failure	OH: Secondaries/Services	492	1.99%	5,620	0.33%	943,435	0.33%
2006	Equipment Failure	OH: Switch - Automatic	97	0.39%	23,662	1.37%	2,664,659	0.94%
2006	Equipment Failure	OH: Switch - Manual	397	1.60%	13,063	0.76%	1,251,817	0.44%
2006	Equipment Failure	OH: Tap Fuse/Cutout	496	2.00%	15,331	0.89%	2,017,529	0.72%
2006	Equipment Failure	OH: Transformer/Transformer Fuse	2,231	9.02%	49,145	2.85%	6,499,466	2.30%
2006	Equipment Failure	Subs/Swyd: Insulator	1	0.00%	1,308	0.08%	51,012	0.02%
2006	Equipment Failure	Subs/Swyd: Power Wiring	1	0.00%	2,770	0.16%	142,268	0.05%
2006	Equipment Failure	Subs/Swyd: Switch-Automatic	16	0.06%	31,749	1.84%	2,731,842	0.97%
2006	Equipment Failure	Subs/Swyd: Switch-Manual	1	0.00%	3,689	0.21%	92,225	0.03%
2006	Equipment Failure	Subs/Swyd: Transformer	1	0.00%	3,324	0.19%	125,448	0.04%
2006	Equipment Failure	UG: Elbows	11	0.04%	260	0.02%	88,492	0.03%
2006	Equipment Failure	UG: Load Break Junction	1	0.00%	7	0.00%	2,032	0.00%
2006	Equipment Failure	UG: Low Tension Network	1	0.00%	8	0.00%	1,248	0.00%
2006	Equipment Failure	UG: Other Equipment - Explain	10	0.04%	123	0.01%	31,807	0.01%
2006	Equipment Failure	UG: Pads/Vaults/Manholes/Splice Boxes	10	0.04%	125	0.01%	28,228	0.01%
2006	Equipment Failure	UG: Primary/Cable/Neutral	490	1.98%	23,572	1.37%	6,256,268	2.22%
2006	Equipment Failure	UG: Riser Pole Equip/Terminator/Lightning Arrestor	54	0.22%	2,228	0.13%	303,747	0.11%
2006	Equipment Failure	UG: Secondaries/Services	90	0.36%	497	0.03%	133,771	0.05%
2006	Equipment Failure	UG: Switchgear	4	0.02%	73	0.00%	17,772	0.01%
2006	Equipment Failure	UG: Transformer/Transformer Fuse	169	0.68%	1,984	0.12%	576,801	0.20%
2006	**Equipment Failure**	**All Components**	**5,809**	**23.48%**	**474,976**	**27.58%**	**58,597,037**	**20.77%**
2006	**All Causes**		**24,745**	**100.00%**	**1,722,363**	**100.00%**	**282,088,285**	**100.00%**

Attachment 3

PPL Electric Initiatives to Reduce SAIDI

Summary:

The following table provides estimates of cost and reliability improvements from initiatives developed by PPL Electric to improve SAIDI by reducing SAIFI or CAIDI. They are ranked from the least expensive (per SAIDI minute) to highest. As these initiatives are implemented, PPL Electric continuously updates the estimates of cost and reliability improvements. Note that the SAIDI improvements, in minutes, are PPL Electric's best estimate of the net effects which reflect multiple initiatives affecting the same equipment, facilities, and customers.

Initiative	Capital Cost	Annual O&M Cost	Potential SAIDI Improvement (minutes)	Approx. Cost/SAIDI Minute[1]
EZ Restore Tool	$80,000		2 -3 -	$6,000
Restore before Repair		$200,000	10 - 12	$18,000
Regional Troublemen		$250,000	12 -15	$20,000
Increased Sectionalizing		$350,000	10 - 15	$30,000
Remote OCR Operation	$1,500,000		2 - 3	$75,000
Increased Line Inspections	$250,000	$200,000	2 - 3	$80,000
Intelligent Sectionalizing	$5,000,000		2 - 4	$250,000
Increased Transfers	$5,000,000		2 - 3	$250,000
Increased Tree Trimming		$5,500,000	10 - 15	$450,000

Discussion & Details

- EZ Restore Tool: Purchase new tools to locate faults in underground cables (URD) to more quickly isolate the faulted section. This tool can be used by a single crew, eliminating the need for call-out of a second crew. The goal is to reduce CAIDI by more quickly isolating URD faults and restoring as many customers as possible. The estimated cost of about **$80,000** which can be capitalized. The estimated potential SAIDI improvement is about **2 - 3 minutes.**

- Restore before Repair: Enforce the procedure to first isolate a fault and restore as many customers as possible before attempting repair. Dispatch additional linemen to assist with switching/sectionalizing. The goal is to reduce the number of customers affected by otherwise long duration outages to reduce CAIDI. The estimated cost is about **$200,000 per year** due to increased call-outs and reduced productivity. The estimated potential reduction in SAIDI is about **10 - 12 minutes.**

- Regional Troublemen: Add additional Troublemen throughout the PPL Electric system, working around-the-clock, with at least two Troublemen per region. Also included is staggering start times of line crews during Daylight Savings Time. The goal is to have more PPL Electric crews on-site

[1] Assumes a 15% Carrying Charge Rate for Capital Costs

during the early evening, and repairmen throughout the night, to more promptly respond to routine customer outages by reducing the number of potential call-outs. The estimated cost is about **$250,000 per year** in increased wages and benefits, is expected to reduce CAIDI, and lead to a potential reduction in SAIDI of about **12 - 15 minutes** per year.

- Increased Sectionalizing: This continues a past initiative to ensure that all single phase taps are fused, and that additional sectionalizing devices are added where warranted. The goal is reduce SAIFI by reducing the number of customers affected by a fault. The total cost of this program is $350,000 spread over 5 years. The potential estimated reduction in SAIDI is **10 - 15 minutes.**

- Remote Recloser Monitoring & Operation: Where Intelligent Sectionalizing cannot be applied due to lack of ties or economics, this project will permit the local system operator to be alerted immediately if a Circuit Recloser trips to lockout, and then remotely sectionalize and/or reclose the device without needing to dispatch a line crew. This initiative is designed to reduce CAIDI, but will not affect the number of customers seeing a prolonged outage, however, the program is intended to provide faster restoration of service for most customers on the circuit. This program focuses on the worst performing circuits on the system. The cost of this project is about **$1.5 million** which will be capitalized, and has the potential to reduce SAIDI by about **2 - 3 minutes** system wide.

- Increased Line Maintenance Inspections: Increase the number of distribution line miles inspected per year, focusing on the worst performing circuits. Perform infrared thermal imaging of all three-phase and two-phase sections of these circuits. The goal is to identify potential problems with equipment, structures, etc. before they fail, thereby improving SAIFI. The goal is to inspect about 2000 miles/year above the current level. The cost is about **$200,000 per year plus an additional $200,000 in capital costs for repairs**, and the potential reduction in SAIDI is about **2 -3 minutes.**

- Intelligent Sectionalizing: This is a limited application of "distribution automation" for automatic resectionalizing of key distribution circuits. This application is limited to those circuits where there are existing 3-phase ties to alternate sources of supply, or where new ties can be economically created, and where past performance warrants the application of this technology. The goal is to reduce SAIFI by limiting the number of customers experiencing long duration (> 5 minute) outages per event. The cost of this initiative is estimated at about **$ 5.0 million**, which will be capitalized, and the potential improvement in system SAIDI is estimated at between **2 and 4 minutes.**

- Increasing Transfer Capabilities: For all circuits, planners and regional engineers are determining where additional load transfers can be economically established through manual switching. This initiative would decrease CAIDI, with a potential decrease in SAIDI of **2 - 3 minutes.** The cost of this initiative is anticipated to be about **$5 million**, which would be capitalized.

- Increased Tree Trimming: Increase the number of distribution line miles trimmed per year in order to reduce SAIFI. Analysis showed that cycles that achieve about 5,500 miles/year will balance cost and reliability improvements. The additional cost is about **$6 million per year**, and has the potential to reduce SAIDI by about **10 - 15 minutes.**

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February 21, 2007

VIA FEDERAL EXPRESS

Secretary James J. McNulty
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
2nd Floor
400 North Street
Harrisburg, PA 17120

Re: Additional questions regarding Inspection and Maintenance Standards; Docket No. L-00040167

Dear Secretary McNulty:

Enclosed please find an original and three copies of Allegheny Power's responses to additional questions posed by the Pennsylvania Public Utility Commission regarding proposed Inspection and Maintenance standards. An electronic copy has been forwarded to Elizabeth Barnes as requested.

Very Truly Yours,

John L. Munsch

John L. Munsch
Senior Attorney

cc: Elizabeth Barnes (via email)

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FEB 21 2007

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Allegheny Power (West Penn Power)
PA PUC Inspection and Maintenance Standards
Answers to Questions posed at January 22nd, 2007 Technical Conference

PAPUC Request 1:
Please provide Commission staff with your current policies regarding what efforts are being made to reduce the number and duration of outages due to off-right-of-way vegetation. Please be as detailed as possible and include any written policies or other directives to employees and contractors on how the policy is to be implemented.

AP Response:

In 2005, Allegheny Power began a pilot to accelerate its then-existing six-year distribution right-of-way maintenance schedule to a four-year rural distribution maintenance cycle. Under a four-year cycle, vegetation on the entire rural distribution system is maintained at least once in a four-year period.

The Company has concluded that a four-year cycle is the optimum for removing danger trees and performing vegetation maintenance beneath the conductors. More emphasis is being placed on identifying and removing off right-of-way danger trees in order to improve electric service reliability.

Our traditional vegetation maintenance approach to potential off right-of-way danger trees was to address them as they were discovered through the course of performing other scheduled maintenance activities. If the crews noticed obvious dead or occasional live danger trees off of the right-of-way, they were cut down or reduced in height to the point they no longer posed a threat to our facilities. This is still done today. In the past there was no deliberate approach to identifying potential danger trees off the right-of-way.

Allegheny changed the tree outage cause definitions in 2001 as it was recognized that fallen off right-of-way trees were a significant component of our tree related outages. The active tree outage definitions did not allow us to analyze the contribution of these types of trees to AP's overall outage picture. Once changing the outage causes, we came to understand the contribution of fallen or broken off right-of-way trees to our reliability stats. Based on the reliability information we made the decision to shorten our rural maintenance cycles to better focus on mitigating the hazards presented by off right-of-way trees to our facilities.

Allegheny Power has modified its vegetation maintenance to attempt to identify off right-of-way trees with visible disease or damage. The trees that have a high likelihood of structural failure or could cause damage to our facilities are removed. Allegheny Power attempts to notify property owners prior to removing the danger tree.

PAPUC Request 2:
With regard to all information previously provided to the Commission describing your company's current inspection, maintenance and repair standards, Please provide Commission staff with the inspection, maintenance and repair standards existing in 1990, 1995, and 2000. A comparison against the proposed regulations minimum standards in a table format is preferable.

AP Response:
Attached is document "Allegheny Power – PA PUC I&M Standards – Feb 21 – 1" which includes Allegheny Power's estimates of prior inspection and maintenance programs. In many cases, AP was not able to pinpoint maintenance cycles during these specific years with documentation for those years, but we have done our best to piece together the cycles for the items proposed. Allegheny Power provided its programs for 2006 in its comments to the proposed rulemaking.

Attachment: Allegheny Power - PA PUC I&M Standards - Feb 21 – 1.

PAPUC Request 3:

To the extent any of the outage information/statistics you have provided in documents filed with the commission in this rulemaking reflects only frequency or only duration (or is unclear whether it is based on one or the other), please provide the same information addressing both frequency and duration. For example, if a filing states that 1% of customer outage incidents are substation related, please provide the percentage by duration of substation outage minutes to total outage minutes.

AP Response:

The table below shows the relevant percentages of Allegheny Power's Pennsylvania Customer Interruptions (CI) and Customer Minutes Interrupted (CMI), for each of the items mentioned in Allegheny Power's Powerpoint presentation for the January 22nd, 2007 Technical Conference. All data in this table is based on 2003-2006 outage data. Please note that any discrepancies are due to the fact that complete 2006 data was not available at the time the original percentage estimates were calculated.

	Data Provided at Technical Conference		Analysis of 2003-2006 Data	
	Page Reference	Percentages Cited	Frequency *(Customer Interruptions)*	Total Duration *(Customer Minutes Interrupted)*
Transmission (100kV and Above)	Pages 3,8	No CI in 2006, Less than 1% of CI	0.6%	0.5%
Substation-Related	Pages 4,8	1% - 2% of CI	1.7%	1.3%
Distribution	Pages 5,8	97% - 98% of CI	97.7%	98.1%
Reclosers	Page 5	1% of CI	1.3%	0.9%
Overhead Transformers	Page 5	1% - 1.5% of CI	1.1%	1.1%
Poles	Page 5	0.8% of CI	0.6%	0.8%
Underground Transformers	Page 5	0.25% of CI	0.1%	0.3%
Equipment-Related Causes	Page 5	30% of CI	29.2%	22.2%

Note: "CI" is shorthand for "Customer Interruptions".

Allegheny Power (West Penn Power)

PA PUC I&M Standards - Answers to Questions posed at January 22nd Technical Conference

Attachment: Allegheny Power - PA PUC I&M Standards - Feb 21 - 1

PA PUC Proposed I&M Program		AP program in existence		
		1990	1995	2000
1) Vegetation Management	Distribution Cycle of 4 Years	No set cycle. Each service center was transitioning from practice of extensive maintenance on circuit backbone and hotspotting on the remainder to maintenance on entire circuit. Cycling through all circuits with extensive maintenance on entire circuit took approximately 14 years more or less depending upon location. Herbicide cycles ranged from 4 to 6 or more years.	Completed transition to extensive maintenance on entire circuit. Generally speaking, trim cycles in urban areas ranged from 2 to 4 years and in rural areas from 4 to 8 years depending upon growth patterns across a wide geographic area and upon need. Cycles and practices for herbicide brush control varied based upon height, density, growth rates and local needs - generally ranged from 4 to 6 years.	Generally speaking, trim cycles in urban areas ranged from 2 to 4 years and in rural areas from 4 to 8 years depending upon growth patterns across a wide geographic area and upon need. Cycles and practices for herbicide brush control varied based upon height, density, growth rates and local needs - generally ranged from 4 to 8 years.
	Transmission Cycle of 5 Years	No set cycle. Activities determine maintenance needs. Trimming of residential trees occurs more frequently than brush control which occurs more frequently than trimming trees at corridor edge. Each activity is based upon growth patterns across a wide geographic area and upon need. All of these activities occurred on cycles ranging from two years to nine or more years. Hotspot items discovered during periodic inspections are addressed when needed.	No set cycle. Activities determine maintenance needs. Trimming of residential trees occurs more frequently than brush control which occurs more frequently than trimming trees at corridor edge. Each activity is based upon growth patterns across a wide geographic area and upon need. All of these activities occurred on cycles ranging from two years to nine or more years. Hotspot items discovered during periodic inspections are addressed when needed.	No set cycle. Activities determine maintenance needs. Trimming of residential trees occurs more frequently than brush control which occurs more frequently than trimming trees at corridor edge. Each activity is based upon growth patterns across a wide geographic area and upon need. All of these activities occurred on cycles ranging from two years to nine or more years. Hotspot items discovered during periodic inspections are addressed when needed.
2) Pole Inspections	Poles inspected every 10 years	10 years	10 years	12 years
3) Overhead Line Inspection	Transmission Lines inspected aerially twice per year (spring and fall)	Aerial patrols twice/year on 345kV to 500 kV, annually for all other transmission voltage levels.	Aerial patrols twice/year on 345kV to 500 kV, annually for all other transmission voltage levels.	Aerial patrols for all transmission voltages minimum of once per year; comprehensive patrol for 345-500kV every 5 years and for 100-230kV every 10 years.
	Transmission Lines inspected on foot every 2 years	All patrols performed aerially; foot patrols as needed.	All patrols performed aerially; foot patrols as needed.	All patrols performed aerially; foot patrols as needed.
	Distribution Lines inspected on foot every year	Inspected every 10 years.	Inspected every 10 years.	Inspected every 12 years.
	All problems found during inspections fixed within 30 days - DISTRIBUTION	Hazardous conditions repaired as soon as possible; problems without near-term consequences scheduled within following budget cycle.	Hazardous conditions repaired as soon as possible; problems without near-term consequences scheduled within following budget cycle.	Hazardous conditions repaired as soon as possible; problems without near-term consequences scheduled within following budget cycle.
	All problems found during inspections fixed within 30 days - TRANSMISSION	Hazardous conditions repaired as soon as possible; problems without near-term consequences scheduled within following budget cycle.	Hazardous conditions repaired as soon as possible; problems without near-term consequences scheduled within following budget cycle.	Hazardous conditions repaired as soon as possible; problems without near-term consequences scheduled within following budget cycle.
	Overhead transformers visually inspected annually as part of circuit inspection	Inspected in conjunction with circuit inspection.	Inspected in conjunction with circuit inspection.	Inspected in conjunction with circuit inspections.
	Padmounted transformers inspected every 2 years	Inspect every 6 years.	Inspect every 4 years	Inspect every 5 years
	Reclosers inspected and tested every year	Inspect every 3 years	Inspect every 3 years	Inspect every 5 years
4) Substation Inspections	Substation equipment, structures, hardware inspected monthly	Monthly for EHV Stations, Quarterly for Others	Monthly for EHV Stations, Quarterly for Others	Monthly for EHV Stations, Quarterly for Others

FirstEnergy

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(610) 939-8655 (Fax)

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February 28, 2007

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

VIA OVERNIGHT UNITED PARCEL SERVICE

James J. McNulty, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

L-00040167

Re: ***Follow-up Request for EDCs at the Technical Conference of January 22 on Inspection and Maintenance Standards***

Dear Secretary McNulty:

In accordance with your data request of January 23, 2007, enclosed for filing is the Answer of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company (collectively, "FirstEnergy"). An electronic copy is also being filed with Elizabeth Barnes.

Please contact me at the above phone number should you have any questions.

Sincerely,

Linda R. Evers /dm

Linda R. Evers, Esquire

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dlm
Enclosures

c: E. Barnes (via electronic copy)

Equipment	Distribution Lines	1990			1995			2000		
		Met-Ed	Penelec	Penn Power	Met-Ed	Penelec	Penn Power	Met-Ed	Penelec	Penn Power
	Capacitors	na	na	Annual	na	na	Annual	Annual	Annual	Annual
	Wood Poles	na	na	10 Years	na	na	10 Years	13 Years	13 Years	As required
	Reclosers	Oil Reclosers - oil test 5 yr cycle, overhaul 9 yr cycle Met-Ed Elec Maint Manul V/10	na	Annual field inspection and a complete shop inspection performed based upon the number fault operations the device has seen. For the recloser duty to ability ratio (D/A) greater than 75%, remove for shop inspection after 50 operations. For the recloser D/A less than 75%, remove for shop inspection after 100 operations.	Oil Reclosers - oil test 5 yr cycle, overhaul 9 yr cycle Met-Ed Elec Maint Manul V/10	na	Annual field inspection and a complete shop inspection performed based upon the number fault operations the device has seen. For the recloser duty to ability ratio (D/A) greater than 75%, remove for shop inspection after 50 operations. For the recloser D/A less than 75%, remove for shop inspection after 100 operations.	Perform a visual and battery test inspection, or on a four-year cycle a visual and battery test inspection plus a calibration of the electronic control.(WP 2080 GPU) Oil Reclosers - oil test 5 yr cycle, overhaul 9 yr cycle Met-Ed Elec Maint Manul V/10	Perform a visual and battery test inspection, or on a four-year cycle a visual and battery test inspection plus a calibration of the electronic control.(WP 2080 GPU)	Annual field inspection and a complete shop inspection performed based upon the number fault operations the device has seen. For the recloser duty to ability ratio (D/A) greater than 75%, remove for shop inspection after 50 operations. For the recloser D/A less than 75%, remove for shop inspection after 100 operations.
	Radio-Contolled Switches	na	na	na	na	na	na	Annual	Annual	na
	Thermovision	na	na	na	na	na	na	na	na	na

na - After a reasonable investigation, FirstEnergy is not able to verify or confirm its historical practice related to this inquiry.

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Forestry

With regard to all information previously provided to the Commission describing your company's current inspection, maintenance and repair standards, Please provide Commission staff with the inspection, maintenance and repair standards existing in 1990, 1995, and 2000. A comparison against the proposed regulations minimum standards in a table format is preferable.

T he current FirstEnergy Vegetation Management Specification was last revised on 1/1/2003 and reflects the 4-year cycle for distribution VM maintenance and 5-year cycle for transmission VM maintenance. The 1990 and 1995 vegetation management polices (which were pre-GPU/FirstEnergy merger) are not readily available. However, in 2001, GPU reported in its annual report that its VM program consisted of transmission cycle of 6 years and a distribution cycle of 4 years.

FirstEnergy's current policy is consistent with GPU's prior policy with respect to the treatment of tree limbs that form a canopy over the top of distribution feeder main trunks and tap lines. The policy is to inspect all such canopies to determine the health and viability of the limbs and to remove all such limbs that are a danger to the electrical conductors. Dangerous overhanging limbs are limbs with included bark, cracks, splits, decay, dead limbs, with high potential for breaking or bending into conductors because of ice, snow, wind loading. While the current and prior policies are substantially similar, there are differences in the implementation of such policies. The differences are primarily due to the fact that FirstEnergy's vegetation management program includes a formal inspection process for verification of the adherence to FirstEnergy's vegetation management specifications, while GPU relied on contractors to inspect their own work.

	Substations	1990			1995			2000		
		Met-Ed	Penelec	Penn Power	Met-Ed	Penelec	Penn Power	Met-Ed	Penelec	Penn Power
Equipment	General Inspections	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly
	Transformers	4 Years	4 Years	4 Years	4 Years	4 Years	4 Years	6 Years	6 Years	5 Years
	Breakers	4 Years	4 Years	2 Years	4 Years	4 Years	2 Years	6 years	6 Years	2 Years
	Relay schemes	4 Years	4 Years	4 Years	4 Years	4 Years	4 Years	4 Years	4 Years	5 Years
	Thermovision	Annual	Annual	2 Years	2 Years	2 Years	2 Years	2 Years	2 Years	2 Years

Equipment / Transmission Lines	1990			1995			2000		
	Met-Ed	Penelec	Penn Power	Met-Ed	Penelec	Penn Power	Met-Ed	Penelec	Penn Power
Aerial Patrols	na	na	4 months	na	na	6 months	Annual	Annual	6 months
Wood Poles	na	na	10 years	na	na	15 years	10years	10 years	15 years
Steel Poles & Lattice Towers	as required	as required	as required	as required	as required	as required	as required	as required	as required
Air Switches	na	na	as required	na	na	5 year	na	na	5 year
Thermovision	na	na	as required	na	na	as required	3-Year	3-Year	as required

na - After a reasonable investigation, FirstEnergy is not able to verify or confirm its historical practice related to this inquiry.

Pike Count Light and Power responses to :
QUESTIONS AND COMMENTS FOR INTERESTED PARTIES TO ADDRESS AT THE JAN. 22 TECHNICAL CONFERENCE

To ALL EDCs:

Proposed Section 57.198 (Inspection and maintenance standards) provides:

(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.

QUESTIONS:

Does your company have a periodic I&M plan for each type of equipment listed above? If not, please explain why not. Provide specific explanations in your response for each type of equipment.

If your company does have a periodic I&M plan for the equipment listed above, please list the I&M cycles that are followed for each type of equipment.

Device	Maintenance	Interval
Poles	No formal program at this time. It has been found that defective poles have not had a significant impact on reliability and a formal program has not been established at this time.	
OH conductors	Infrared - Three phase - Single and two phase	Annual Every three years
Transformers	Infrared – on three phase lines - on single and two phase lines	Annual Every three years
Switching devices (Reclosers)	Inspection	Annual
Protective devices (fuses)	Infrared – on three phase lines - on single and two phase lines	Annual Every three years
Regulators	Inspection	Annual
Capacitors	Inspection	Annual
Substations	Visual Inspection	Monthly

(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.

QUESTIONS:

For each of the four I&M intervals listed above, what are the I&M intervals utilized by your company?

Procedure	Present I&M Interval	
Vegetation management	Transmission – Distribution –	NA - We have no transmission 3 years
Poles		None
OH Line Inspections	Transmission – Distribution -	NA - We have no transmission No foot patrol but Infrared three phase – annual Infrared 1 & 2 Phase – every three years
Substation Inspections		Monthly

For each of the four I&M intervals, what is an estimate of the annual cost to convert from your company's current interval to those proposed above?

Procedure	Present I&M Interval	
Vegetation management	Transmission – Distribution –	NA - We have no transmission No increase in costs
Poles		$25,000
OH Line Inspections	Transmission – Distribution -	NA - We have no transmission $55,000 line $15,000 OH transformers $10,000 UG transformers
Substation Inspections		No increase in costs

If the Commission were to adopt the edited Annex A version in the AFL-CIO's comments dated November 4, 2006, what would those changes to the regulations cost Pennsylvania ratepayers? Please justify an aggregate figure with specifics.

See Attachment A.

Would the proposed additions to the proposed regulations better reliability performance in the EDC industry?

It is Pike's opinion that improvement in reliability cannot be ascertained at this time. Specific data collection methodology and requirements would need to be established to accumulate data for each additional inspection program. After data has been collected, a cost benefit analysis study could be undertaken.

If the Commission were to adopt minimum repair standards and time frames for corrective actions, what would your EDC recommend they be?

The time frames would be determined by the degree of each defect and its potential impact on reliability. This would be factored into existing work plans and manpower availability. No generic standards are recommended.

Do you have any criticisms of the OCA's proposed revision to Annex A, and if so, what are they?

OCA has not provided any cost benefits that justify these additional programs.

What would the cost be to ratepayers if any in implementing the proposed regulations in Annex as revised by OCA?

See Attachment A.

What would the benefit be?

It is Pike's opinion that improvement in reliability cannot be ascertained at this time. Specific data collection methodology and requirements would need to be established to accumulate data for each additional inspection program. After data has been collected, a cost benefit analysis study could be undertaken.

What are your objections, if any, to a 4-year tree trimming cycle for distribution lines?

Pike prefers to remain with the existing three year trimming cycle.

Would you accept a 5 or 6-year tree-trimming cycle?

Pike prefers to remain with the existing three year trimming cycle.

Would you prefer an average tree-trimming cycle as proposed by Duquesne Light?

Pike prefers to remain with the existing three year trimming cycle.

Estimated Annual Costs to EAPA Member Utilities for Implementation of PA PUC-Proposed Rulemaking on Inspection and Maintenance Standards

Subject	PUC Proposal	AFL/CIO Proposal	OCA Proposal	Estimated Annual Cost Impact - Pike County Light & Power		
MAINTENANCE ITEMS				**PUC Proposal**	**AFL/CIO Proposal**	**OCA Proposal**
1) Vegetation Management	Distribution Cycle of 4 Years	Same	Same	$0	$0	$0
	NOTES					
	Minimum Allowed Clearance between vegetation and transmission and distribution lines (Clearance distance not established in order)	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.	Same	Cannot be determined until standards are set	Much more detail is required to provide an estimate. Do you just do an inspection or is trimming required? Who determines what is wetter than normal and how would trimming cycle be altered?	Cannot be determined until standards are set
	NOTES					
	Transmission Cycle of 5 Years	Same	Same	$0	$0	$0
	NOTES			Pike has no transmission facilities	Pike has no transmission facilities	Pike has no transmission facilities
[illegible]	[illegible]	Distribution poles shall be visually inspected every 10 years. 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	Pole inspections every 10 years, to include drill tests, shell test, load calculation, visual inspection for holes, evidence of insect		$25,000 + Pole replacement costs cannot be	$25,000 + Pole replacement costs cannot be
Plan Submission	EDC's submit a proposed comprehensive plan every 2 years; PUC must approve or reject plan; EDC must rewrite plan if rejected.	The plan must comply with the minimum inspection and maintenance intervals provided for set forth in subsection (e).	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.	Unknown	Unknown	Unknown
	EDC's must submit separate plans for Urban areas vs. Rural areas as defined by US Bureau of Census	Same	Same	$0	$0	$0
		(5) Other inspection requirements. (i) Group-operated line switches shall be inspected and tested annually. (ii) Relays shall be inspected and tested every two years. (iii) Sectionalisers 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.	Other Critical Facilities shall be tested and inspected either annually or every 2 years. Switches inspected and tested annually; relays, sectionalizers and vacuum switches inspected and tested every 2 years. Problems that affect integrity of equipment to be repaired or replaced within 20 days.		Much more detailed specifications must be provided to develop a cost estimate.	Much more detailed specifications must be provided to develop a cost estimate.