UTILITIES, INC.

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April 16, 2007

**VIA EXPRESS MAIL**

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

**Re: Inspection and Maintenance Standards Notice of Proposed Rulemaking, Docket No. L-00040167**

Dear Secretary McNulty:

Enclosed for filing in the above docket please find an original and fifteen copies of the Supplemental Comments of UGI Utilities, Inc. – Electric Division. A copy of these comments has also been served electronically on Elizabeth Barnes at ebarnes@state.pa.us.

Should you have any questions concerning this filing please feel free to contact me.

Very truly yours,

Mark C. Morrow

Counsel for UGI Utilities, Inc. – Electric Division

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 |

**SUPPLEMENTAL COMMENTS OF UGI UTILITIES, INC. – ELECTRIC DIVISION**

UGI Utilities, Inc. – Electric Division ("UGI") appreciates this opportunity to submit additional comments in response to the above-captioned proposed rulemaking order. UGI previously submitted Comments on February 9, 2005 and Reply Comments on March 11, 2005 in response to the Commission's Advance Notice of Proposed Rulemaking at this docket and comments on November 6, 2007 in response to the Proposed Rulemaking Order published in the Pennsylvania Bulletin on October 7, 2006,. UGI urges the Commission to consider those comments again as it establishes its policy in this area. UGI has also joined with other Pennsylvania Electric Distribution Companies ("EDC") in the comments of the Energy Association of Pennsylvania at this docket, and fully supports those comments. The purpose of these comments is to (1) respond to the questions posed in the Secretarial Order dated January 9, 2007 in this docket and (2) to provide some additional comments on these extremely important issues.

## UGI UTILITIES – ELECTRIC DIVISION RESPONSE TO THE SECRETARIAL ORDER QUESTIONS

Question: Proposed Section 57.198 (Inspection and maintenance standards) provides:

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.

(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?

Response: UGI has an Inspection and Maintenance Plan which is summarized in the chart listed as <u>Attachment 1</u>. This chart shows the inspection and maintenance cycle UGI follows for its facilities.

Question: 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:

The table below summarizes the estimated annual cost of meeting the proposed Inspection and Maintenance intervals proposed above.

| Subject | PUC Proposal | Current Practice | Estimated Cost / Resource Impact |
|---|---|---|---|
| Vegetation Management | Distribution Cycle of 4 Years | Distribution Cycle is presently 7 years for rural feeders and 4 years for urban feeders. Actual work is scheduled based on results of annual visual inspection of each distribution feeder. | Additional $800,000 a year would be needed for an additional 20 workers. |
| | Transmission Cycle of 5 Years | Transmission Cycle is presently 10 years for side trimming and 5 years for brush control. Actual scheduling of work is determined with bi-annual foot patrols of each line. Danger trees identified in these patrols are scheduled for removal ASAP. | Additional $50,000 a years would be needed for a partial addition of 2 workers |
| Pole Inspections | Inspect poles every 10 years. | Poles already inspected every 10 years. | None |
| Overhead Line Inspections | Inspect Transmission Lines aerially twice a year (spring and fall). | Lines are inspected by ground patrol annually. | Additional $20,000 per year. |
| | Inspect Transmission lines on foot every 2 years. | Lines are by ground patrol annually. | No additional Costs. |
| | Inspect Distribution lines on foot every year. | Distribution lines are inspected every 10 years during pole inspections. | Additional costs - $250,000 per year. |
| | All Transmission problems found during inspections fixed within 30 days. | Schedule based on severity of problems. | Additional costs - $200,000 per year. |
| | All Distribution problems found during inspections fixed within 30 days. | Schedule based on severity of problems. | Additional costs - $100,000 per year. |
| | Overhead transformers | Visually inspected along | Additional costs |

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| | visually inspected annually as part of circuit inspection<br><br>Underground transformers inspected every 2 years.<br><br>Reclosers inspected and tested every year. | with lines every 10 years.<br><br>Underground transformers are inspected every 10 years as part of regular program.<br><br>Reclosers are replaced, tested and maintained every 10 years. Unusual conditions are addressed as they occur – excessive operations, mis-operation, etc. | included with circuit inspection above.<br><br>Additional costs - $100,000 per year.<br><br>Additional cost - $500,000 per year. |
| Substation Inspections | Substation equipment, structures, hardware inspected monthly. | 230Kv substation inspected semi-monthly. 69Kv substations inspected monthly. | No additional costs. |

Question: 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?

Response: Please see the following table which shows UGI's cost estimate of complying with the additional items proposed by the AFL-CIO.

| AFL-CIO Suggested I & M Requirements | Estimated Annual Cost |
|---|---|
| Group-operated line switches to be inspected and tested annually | **$310,000** |
| Relays to be inspected and tested every two years | **$85,000** |
| Sectionalisers to be inspected and tested every two years | **$250,000** |
| Vacuum switches to be inspected and tested every two years | **$0** |
| Underground vaults with larger connections (750 Mcm or larger) to be visually inspected and thermo-vision tested for hot spots annually. | **$30,000** |
| Vaults of any size that serve schools, hospitals, public buildings, or residences to be visually inspected and cleaned once per year. | **$100,000** |
| ***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. | **$130,000** |
| **Total Annual Incremental Costs Applicable to AFL-CIO Proposal** | **$905,000** |

The additional costs above are the incremental labor, transportation, contractor and materials expenses to do the additional work. The additional work suggested by the AFL-CIO will not materially enhance the reliability of UGI's service. In order to perform those additional functions, additional labor will be required.

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

Response: UGI urges the Commission not to impose minimum repair standards and time frames for corrective action. Each required repair is different and the appropriate response is dictated by the severity of the problem found. Some repairs can de delayed until the normal cycle of maintenance is reached because the safety of UGI's system is not compromised, the impact on reliability is not affected and other more important work is required. Repairs that require immediately attention will obviously be addressed when found. UGI has developed an inspection and maintenance program that allows UGI to flexibly shift its resources to address the most critical issues first. Both weather and other unexpected events occur. These unexpected events can cause deviations from the plan as UGI will adjust its resources to work on more immediate issues and defer less urgent maintenance. Unlimited resources will not be available to respond to priority repair and maintenance work while at the same time dedicating resources to maintenance and repair work scheduled according to rigid time frames. This would be a needless waste of resources, as often crews would be idle waiting for projects to occur. This would cause customer rates to substantially increase with no commensurate benefit for our customers in terms of increased reliability. The allocation of resources and prioritization of workload should always be the prerogative of each company as outlined in each company's I&M plan. Rigid time frames for repair of equipment will most probably require less important work to be scheduled ahead of more important repair work, capital projects or maintenance projects that would improve reliability. Should a company's allocation of resources allow reliability to decline, the Commission already has, through the reliability regulations, the performance measurement and recourse options at its disposal to address the decline in reliability. Rigid time frames for repair of transmission facilities are impractical because all transmission repair work must be scheduled through PJM. Depending on PJM's current operations and other ongoing maintenance, PJM will prioritize scheduled system repairs without regard for any arbitrary regulatory maintenance deadline.

If the Commission does implement minimum repair standards and time frames, they should be based on individual plans filed with the Commission by each EDC.

Question: 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?

Response: UGI believes the intrusive inspections of transmission and distribution substation transformers as specified by to OCA would damage the transformers, void the manufactures warranty, and works against improving the reliability of the delivery system. It is generally contrary to "good utility practice." Further, UGI would have to contract for this service at a higher cost. UGI also believes it is impossible to take these units on its system out of service for inspections with the frequency and duration the OCA specifies and still provide reliable service to its customers. Most likely, PJM would not allow taking the transmission substation transformers out of service as would be required without building additional redundancy into the substations, so it would be impossible to meet this regulatory requirement.

An overlooked fact pertinent to all these recommendations is the detrimental affect on customer service reliability of the equipment outages required to perform the prescribed inspection and maintenance. Each piece of equipment must be taken out of service to be maintained. The customer is denied the benefit of each piece of equipment while it is out for inspection and maintenance. For example, UGI has three 230/69 kV transformers on its system. The annual intrusive inspection of these units recommended by the OCA would require each unit to be removed from service for approximately two weeks for inspection at a cost of approximately $60,000 per unit. Therefore, UGI's customers will be denied the benefit of six transformer-weeks of service each year to meet this one Inspection and Maintenance requirement. They will not have the system reinforcement contribution of these transformers while these units are out of service being inspected. UGI believes that the net result is its system will be operating less reliably during these long transformer outages. Add to this the cumulative negative contributions to reliability the removal from service for inspection and maintenance of each of the other pieces equipment UGI has on its system and the consequence to service reliability is significant. The bottom line is UGI's equipment investment must remain in service doing its job to benefit its customers. It provides the customer no reliability benefit when it is unavailable, even for inspection and maintenance. UGI strongly asserts that when the detrimental effect to customer service reliability during the increased equipment outages is netted against any positive benefits more frequent inspection and maintenance might provide will result in an overall decline in reliability of service to its customers.

Shown below are the additional annual expenses that would result from the OCA's proposal.

| OCA's Suggested I & M Requirements | Estimated Annual Cost |
|---|---|
| **Transmission and distribution substations**: Annual detailed inspections that include inspection by infrared scanning. A component discovered through infrared scan to be more than 100 degrees centigrade above ambient temperature should be addressed within 30 days | **$20,000** |
| **Substation transformers supplying transmission lines**: Annual intrusive inspection. Deficiencies identified should be repaired or addressed within 30 days. | **$180,000** |
| **Substation transformers supplying distribution lines**: Intrusive inspection every two years that includes bushing testing, dissolved gas analysis and other testing. Deficiencies identified should be repaired or addressed within 60 days. | **$115,000** |
| **Transmission Lines and all attached equipment**: Annual detailed inspection that includes visual inspection and infrared scanning. A component identified through infrared scan to be more than 100 degrees centigrade above ambient temperature should be addressed within 30 days. | **$20,000** |

| | |
|---|---|
| **<u>Distribution Line and all attached equipment (transformers, switching/protective devices, reclosers, regulators/capacitors)</u>**: Patrol inspection once every two years and a detailed inspection once every five years. A component discovered through infrared scan to be more than 100 degrees centigrade ambient temperature should be addressed <u>within 30 days</u>. | **$250,000** |
| **<u>Wood Poles</u>**: Detailed inspection once every ten years with an intrusive inspection of those poles identified as having potential problems through the detailed inspection. Poles with major deficiencies that considerably affect the strength of the pole should be replaced <u>within 60 days</u>. | **$0 - Consistent with UGI's current program** |
| **Total Annual Incremental Costs Applicable to the OCA's Proposals** | **$585,000** |

Question: 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: UGI's vegetation management program is simply to assess tree conditions together with circuit performance and trim as need. It results in distribution trim cycles of approximately 7 years for rural feeders and 4 years for urban feeders. Trim cycles times vary from feeder to feeder and annual tree growth. The width of the right of way is always a factor in determining trim cycles. A narrower right of way will need to be trimmed more frequently than a wider right of way as growth from outside the right of way will become an issue more frequently on a narrower right of way. Actual work is scheduled based on results of annual visual inspection of each distribution feeder. This results in the most efficient allocation of line clearance resources.

UGI manages the vegetation on its transmission lines the same way it does on its distribution circuits. The resultant transmission line trim cycle is approximately 10 years for side trimming and 5 years for brush control. Actual scheduling of work is determined by annual foot patrol of each line. Danger trees identified in these patrols are scheduled for removal ASAP.

UGI believes a rigid time based tree trimming cycle is counter productive. Flexibility is needed in determining when vegetation management work must be conducted. Mandating a uniform four-year tree-trimming cycle for distribution lines in itself accomplishes very little toward improving service reliability. Line clearance is a condition-based activity. UGI schedules tree-trimming on its circuits based upon its own individually established criteria as part of a comprehensive program that is flexible enough to integrate equipment and technological improvements. Basically, a circuit is trimmed when it needs to be trimmed; much like a homeowner cuts their grass when it needs cutting, rather than on a specific schedule. Trimming too soon results in wasting part of the value of the work done during the last trimming; trimming too late results in poor circuit performance. The clearance desired at the time of pruning is related to many factors including individual forest types and tree species, local environmental conditions (including temperature and rainfall), the trimming specification, the type of wire and its configuration, property owner concerns, right of way agreement provisions and the aesthetics of the tree.

It is the responsibility of a skilled and experienced Line Clearance Supervisor to decide on which circuits should be trimmed. It involves bringing together a number of factors and applying judgment on 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 the supervisor judges the likelihood of the tree conditions causing a circuit interruption in the coming year. The supervisor 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. The supervisor also looks for danger trees during this patrol. In addition, the supervisor keeps track of the annual tree related interruptions by circuit and when the circuit was last trimmed. The supervisor 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. Work is then scheduled 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.

The Commission should permit each EDC the flexibility to determine the vegetation management program that best suits the unique attributes of its territory, and flexibility to determine what should be done when the circuit is maintained.

## ADDITIONAL COMMENTS

As UGI discussed in its prior comments, the costs and benefits of prescriptive inspection and maintenance regulations are negative. UGI's reliability will not be improved very much and could actually be harmed. Maintaining a flexible inspection and maintenance program is vital to ensuring reliable electric operations without imposing upon the customer an increased financial burden. As explained in UGI's November 6, 2006 comments, the proposed regulations would increase UGI annual inspection and maintenance costs by approximately $2 million. Since UGI will not be able to absorb these increased costs, UGI will be forced to pass this amount through to customers. A rate increase of this magnitude would increase distribution rates by approximately 6%. UGI noted in the Technical Conference that if it were to follow the proposed regulations, there would be on average 11 under best case assumptions.

Final regulations must be flexible enough to allow UGI to utilize its management expertise to allocate its resources where they are most needed to provide a safe and reliable system. The proposed regulations are simply too prescriptive to allow such management discretion. The unintended consequence will be that UGI's costs and customer rates will increase significantly with a corresponding decrease in reliability as more effort is spent on projects that meet rigid time requirements in lieu of those projects designed to improve the reliability of the system.

In summary, UGI can foresee no benefits for anyone from prescriptive inspection and maintenance standards.

Attachment 1

## UGI Inspection and Maintenance Plan

Lines and Line Equipment

UGI's current inspection and maintenance plan for lines and line equipment is as follows:

| Facilities | Inspection and Maintenance Plan |
|---|---|
| | |
| **Poles** | I & M - 10 Years |
| **Underground Facilities** | I & M - 10 Years |
| **Reclosers/Sectionalizers (1)** | Maintain - 5 Years/100 Operations |
| **Distribution Switches** | I & M - 5 Years |
| **Capacitors (2)** | Inspect - Semi - Annually |
| **Voltage Regulators** | Inspect - Monthly<br>Maintain - 10 Years/100,000 Operations |
| **Transmission Lines (2) (3)** | Patrol Annually |
| **Transmission Line Switches** | Inspect - Annually<br>Maintain - Bi - Annually |
| **Transmission Line Towers - Painting** | 10 Years |

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

Attachment 1

## UGI Inspection and Maintenance Plan

Substations

UGI's inspection and maintenance plan for substation equipment is as follow:

| Facilities | Inspection and Maintenance Plan |
|---|---|
| **SUBSTATIONS** | |
| **Routine Inspections - 230kV** | Semi-Monthly |
| **Routine Inspections - ≤ 69kV** | Monthly |
| | |
| **Switches** | |
| **Circuit Switcher** | 2 Years |
| **MOAB** | 2 Years |
| **69kV & 230 kV Disconnects** | 2 Years |
| **13kV & 4 kV Disconnects** | 5 Years |
| | |
| **TRANSMISSION TRANSFORMERS - 230kV/69Kv** | |
| **External Inspection** | Semi-Monthly |
| **Dissolved Gas Test** | Semi-Annually |
| **Oil Quality Analysis** | Semi-Annually |
| **Power Factor Test** | 2 Years |
| | |
| **DISTRIBUTION TRANSFORMERS - 69kV/13kV & 13Kv/4kV** | |
| **External Inspection** | Monthly |
| **Dissolved Gas Test** | Annually |
| **Oil Quality Analysis** | Annually |
| **Power Factor Test** | 5 Years |
| | |
| **CIRCUIT BREAKERS – OIL/VACUUM/AIR ≤ 15kV** | |
| **Internal Inspection** | 6 Years |
| **External Inspection** | Monthly |
| **Oil Dielectric/ Hi Pot** | 6 Years |

| | |
|---|---|
| **Ductor Test** | 6 Years |
| **Mechanism Check** | 6 Years |
| **Operational Test** | 6 Years |
| | |
| **CIRCUIT BREAKERS – OIL/GAS - 69kV/Gas 230 kV** | |
| **Internal Inspection (1)** | |
| **External Inspection** | Monthly |
| **Oil Dielectric (2)** | |
| **Ductor Test** | 2 Years |
| **Mechanism Check** | 2 Years |
| **Power Factor Test** | 2 Years |
| **Motion Analysis** | 2 Years |
| **Batteries** | Annually |
| **Infrared Scan** | Annually |
| **INSTRUMENT TRANSFORMER** | |
| **Power Factor Test** | 4 Years |

Notes:

(1) Internal Inspection of Gas 69 kV and Gas 230 kV circuit breakers is based upon the number of fault interruptions and manufacturer's recommendation.

(2) Oil Dielectric testing does not apply to Gas 69 kV and Gas 230 kV circuit breakers.