Good morning. My name is Eric Dickson, and I would like to thank the Commission and its staff for giving FirstEnergy an opportunity to speak at today's proceeding. I am the Director of Operations Services for FirstEnergy, and I am responsible for the company's distribution maintenance practices in addition to having the responsibility for the reliability reporting requirements for FirstEnergy, including Penelec, Penn Power, and Met-Ed. Going forward I will just reference these as the "Companies". I also served as the lead for Energy Delivery in the reliability investigation of the PA operating companies in 2004. I have nearly 30 years of operations experience.

I would first like to clarify the remarks made by the AFL-CIO regarding Ohio's Electric Service and Safety Standards, or ESSS. Basically each company was required to submit a plan to the PUCO for various programs that the Commission wanted to see addressed. Annually, each company reports against its plan as it is not a one-size-fits-all prescriptive program for each EDC. Any changes to the plan must be submitted to the Commission for approval 90 days prior to the beginning of the succeeding calendar year. To assure compliance with the plan, the PUCO has field auditors that meet regularly with the EDC staff members to discuss their programs, typically twice a month, and perform field audits for each of the established programs. Ohio's program is very similar to what was proposed by PPL.

I would like to first address the questions that the Commission has relative to FirstEnergy's inspection and maintenance practices.

We currently perform groundline inspections on a 10-year cycle for transmission and distribution poles.

For our underground distribution facilities, we have a 5-year security inspection cycle which assures the proper security on the transformer is in place, including a pentahead bolt and a lock. It will also assure no gaps are present, i.e. erosion, that would allow the insertion of a wire into the cabinet where the primary and secondary connections are located.

The Companies also perform distribution circuit inspections on a 5-year cycle which identify equipment problems on the facilities inspected which would include the appurtenances on the pole such as arresters, transformers, regulators, wires, and cable. Items requiring immediate attention are phoned into the dispatching office for repair to assure the safety of our workers and the public.

Capacitors – we perform an annual inspection in April/May to assure they are operational prior to the summer season.
Line Reclosers – we perform quarterly inspections and document the number
of momentary operations to make sure our customers are not
experiencing an abnormal number of momentary operations. This inspection
provides a chance to observe any damage to the equipment and make
necessary repairs. There is a proposal by others to inspect and test, which I
understand means to remove, the reclosers every 2 years. This is absolutely
unnecessary inasmuch as it conflicts the manufacturers recommendations and
industry practices which are based on the number of operations and the fault
current for which the device is exposed. This is just one example of where a
purely time-based maintenance program does not make sense.

Substation Inspections
- We perform monthly substation inspections
- We have a robust set of substation preferred maintenance practices which
  include performing annual infrared scans of all substations as of 2005.
  Prior to the reliability settlement, we did perform these infrared
  inspections, but they were performed every other year. Major deficiencies
  are resolved promptly (within one week), and deficiencies are typically
  resolved within the next 30 days.
- We also perform a dissolved gas analysis of our substation transformers
  on an annual basis.
- As I explained previously on the maintenance of distribution line reclosers,
  we are opposed to the intrusive testing of substation equipment on a
  purely time basis as proposed by others. It is not logical to tear apart a
  piece of substation equipment that has historically been operationally
  sound.

Vegetation Management
- First of all, the Companies are already on a 4-year distribution and 5-year
  transmission vegetation management cycle in PA. So the current
  proposal does not impact the costs for the Companies. Tree trimming
  represents an investment of over $100M annually at FirstEnergy, with
  approximately $30M being spent in Pennsylvania last year.

- It should also be noted that per our outage management statistics that
  approximately 87% of our tree related outages are actually caused by
  healthy trees from off the right of way falling into the conductors. As a part
  of our routine cycle, we remove dead, dying, diseased or leaning trees off
  the R/W that could cause a problem to our electric facilities. Unfortunately, it is not possible to identify all trees that will fail. Internal
decay and loose soil conditions cannot be anticipated. Therefore, no
amount of additional inspection or tree pruning will solve this problem.
This issue is further complicated by not having a legal right to trim or
remove trees off the right of way.
• This statistic is further supported by a study, "Research on How Trees Cause Interruptions – Applications to Vegetation Management" which indicates that tree branches growing into distribution conductors do not normally cause outages. Therefore we feel that the proposal to provide for minimum clearances of vegetation from overhead distribution lines to prevent contact with the facilities is unreasonable and could lead to increase cycle frequency and costs while failing to provide any substantive benefit to reliability.

• Tree wire clearance at the time of pruning is not totally dependent on cycle frequency. There are several factors that influence tree clearances, including tree species, local environmental conditions, construction type and easement rights.

• The combined Arborist experience for all of the Pennsylvania Utility forestry staffs is almost 1000 years of combined experience managing vegetation around power lines. Most have 4-year degrees in addition to being Certified Arborists. All of them have the knowledge and expertise to manage the specific vegetation requirements in their operating company.

• The NERC Vegetation Standard FAC-003-1 covers the oversight of transmission vegetation management, and FirstEnergy feels that the commission should recognize that a transmission standard will become fully effective on 2/7/2007 and is applicable throughout North America. To duplicate standards, or worse develop standards that conflict with the NERC standards, would not be appropriate.

Transmission Maintenance – FirstEnergy also has a comprehensive maintenance program which I would like to discuss

• Twice-a-year aerial patrols are performed to assess the overall condition of the system, looking for problems including structural damage and R/W encroachment
• Annual aerial patrol with a trained forester in the helicopter to determine if there are any vegetation issues need to be addressed
• Comprehensive inspections are also performed every 4-5 years requiring the helicopter to hover over each structure to make detailed condition assessment of hardware. These inspections are far superior to a foot patrol as we have found conditions that could have never been determined through a foot patrol. Photographs using a telephoto lens are taken to convey the extent of damage to the appropriate operations personnel. I have provided some of these photographs to the staff for their review and to note the level of detail. One photograph shows a cotter key missing which, had it not be repaired immediately, the wire would have ultimately fallen. The repair work identified in this process is prioritized based on the criticality of the line and the associated repair.
Specifying a time frame for which these repairs need to be completed as others have suggested fails to recognize the ability/inability to get the line out of service or the extent of the equipment condition observed. Utilities need to be able to manage this work by evaluating the risk and ability to get the line out of service without negatively impacting the reliability of the system.

- As I indicated previously, we perform ground-line inspections of wood transmission poles every 10 years.

**Costs to Convert to Proposed I&M Standards – See Attachment A**

At the end of the day, a good I&M program is measured by reliability performance – the quality of electric service provided to our customers. After all, our customers are the reason why we are in business in the first place. I would also like to clarify the reliability information provided by the AFL-CIO inasmuch as the numbers provided were for 2005 and did not convey the significant improvements achieved in 2006. Penelec’s SAIDI improved from 284 to 158, a 44% improvement. Penn Power’s SAIDI, although not discussed by the AFL-CIO, improved from 236 to 139, a 41% improvement. Although we did not achieve the improvement expected in Met-Ed in 2006 based on the work performed, we will continue to focus on the same capital intensive solutions involving the installation of fuses and reclosers that made Penelec successful.

The employees of Penn Power, Penelec, and Met-Ed have worked tirelessly and diligently to improve our service to our customers which is partly attributed to our robust I&M program.

In addition to the robust I&M plans, the Companies need to continue to have the flexibility to target capital resources to the real drivers of reliability performance for SAIFI, CAIDI, and SAIDI. These drivers will change over time and will be different for individual circuits. The generic allocation of resources for all circuits as currently proposed will likely have a negative impact on EDC’s ability to improve reliability performance.

It is the Companies’ goal to achieve the Commissions standards and benchmarks and to be world class. We look forward to working with the Commission staff to achieve these goals.
## Attachment A – FirstEnergy’s Costs for Proposed I&M Standards

<table>
<thead>
<tr>
<th>Subject</th>
<th>PUC Proposal</th>
<th>Current Practice</th>
<th>Potential Impact</th>
<th>Estimated Cost and/or Resource Impact and Details</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>1) Vegetation Management</strong></td>
<td>Distribution Cycle of 4 Years</td>
<td>Distribution Cycle of 4 Years</td>
<td>None</td>
<td>None</td>
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<tr>
<td></td>
<td>FE Vegetation Management Practices</td>
<td></td>
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<td></td>
<td>Minimum Allowed Clearance between vegetation and transmission and distribution lines (Clearance distance not established in order)</td>
<td>All routine vegetation clearing work is performed in compliance with ANSI Z133.1 and A-300 standards. The Company will also be following the NERC standards when issued (expected in early 2007). FE Vegetation Management Practices</td>
<td>None</td>
<td>None</td>
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<tr>
<td></td>
<td>Transmission Cycle of 5 Years</td>
<td>Transmission Cycle of 5 years.</td>
<td>None</td>
<td></td>
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<tr>
<td><strong>2) Pole Inspections</strong></td>
<td>Poles inspected every 10 years</td>
<td>Distribution poles inspected every 10 years Distribution Wood Pole Inspection &amp; Maintenance Practice, Section 2.1</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td></td>
<td>Transmission Lines inspected aerially twice per year (spring and fall)</td>
<td>Transmission wood poles inspected every 10 years</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td></td>
<td>Subtransmission and Transmission Lines are inspected aerially twice per year. T&amp;D Maintenance Manual - Overhead Subtransmission &amp; Transmission - Line Patrolling</td>
<td></td>
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<tr>
<td><strong>3) Overhead Line Inspection</strong></td>
<td>Transmission Lines inspected on foot every 2 years</td>
<td>All Subtransmission and Transmission (23-345kV) lines should be foot-patrolled as required by circuit performance or other special situations. Comprehensive aerial patrols are performed every 4-5 years (foot patrols in areas that cannot be flown). T&amp;D Maintenance Manual - Overhead Subtransmission &amp; Transmission - Line Patrolling</td>
<td>The results of aerial patrols have been found to be significantly better, than the results of foot patrols, as had been performed in the past. Any cost here would bring no benefit.</td>
<td>$360,000/yr or 3 FTE’s (or “Full Time Equivalent” people) effort to inspect.</td>
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</table>
## Attachment A – FirstEnergy’s Costs for Proposed I&M Standards

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<tr>
<td>3) Overhead Line Inspection (continued)</td>
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<tr>
<td><strong>Distribution Lines inspected on foot every year</strong></td>
<td>Distribution lines are inspected every 5 years; the FirstEnergy inspection practice does not require a &quot;foot patrol.&quot; Distribution Circuit &amp; Equipment Inspection Program</td>
<td>There is a significant increase in distribution circuit inspection costs (primarily manpower), plus the difference in FirstEnergy’s inspection program and the &quot;on foot&quot; PA program. Estimate 18 addition people to do inspections, prepare work packages, and monitor progress. FE has over 32,000 miles of distribution line exposure in PA.</td>
<td>$1.95M/ yr or 15 FTE’s effort to inspect, plus 3 FTEs for data preparation &amp; tracking.</td>
<td></td>
</tr>
<tr>
<td><strong>All problems found during inspections fixed within 30 days - DISTRIBUTION</strong></td>
<td>This work is currently scheduled based on severity of problem. Critical and safety related items are repaired as soon as possible, while less severe findings my be repaired as late as within the following calendar year.</td>
<td>This could impact when distribution line inspections are performed due to the need to keep the availability of crews for repair work in mind. Decreased flexibility with regards to the use of line crews and potential increases in cost due to the inability to group repairs in an area for internal or external labor.</td>
<td>Unknown, see comments to left</td>
<td></td>
</tr>
<tr>
<td><strong>All problems found during inspections fixed within 30 days - TRANSMISSION</strong></td>
<td>Schedule based on severity; Transmission system outage must be scheduled through PJM. PJM requirements offer barriers severely limiting the Company’s ability to meet this requirement, except for emergency repairs. Decreased flexibility with regards to the use of line crews and potential increases in cost due to the inability to group repairs in an area for internal or external labor.</td>
<td>Not possible, see comments to left</td>
<td></td>
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</tr>
<tr>
<td><strong>Overhead transformers visually inspected annually as part of circuit inspection</strong></td>
<td>Inspected visually along with current five year circuit inspection. Distribution Circuit &amp; Equipment Inspection Program</td>
<td>Included in &quot;circuit inspection&quot; impact above.</td>
<td>Included in &quot;circuit inspection&quot; impact above.</td>
<td></td>
</tr>
<tr>
<td><strong>Underground transformers inspected every 2 years</strong></td>
<td>Underground equipment inspected every 5 years for security and access; every 15 years for a full inspection. Underground Inspection and Maintenance Practice</td>
<td>Impact would be an increase in costs and efforts.</td>
<td>$1.2M/yr or 9 line FTEs, plus another 1 FTE for data preparation and tracking.</td>
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</table>
### Attachment A – FirstEnergy’s Costs for Proposed I&M Standards

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</tr>
</thead>
<tbody>
<tr>
<td>Reclosers</td>
<td>Reclosers inspected and tested every year</td>
<td>Line recloser trip readings taken four times per year; reclosers are visually inspected once a year, and tested based on number of operations (estimated cycle time for testing is 5 years).</td>
<td>Line recloser testing would require a change out of the existing units, requiring both a significant inventory of &quot;rotation and test spares&quot; and manpower. In its three PA operating companies, FE has more than 3000 line reclosers in service.</td>
<td>$1.6M/yr or 10 line FTEs, plus another 3 shop and staff FTE’s for testing in the shop, data preparation and tracking.</td>
</tr>
</tbody>
</table>

4) Substation Inspections

| Substation equipment, structures, hardware inspected monthly | Substations are visually inspected once per month. | None | None |

OCA vi) Other Critical Facilities

| Switches shall be inspected and tested annually. | Manually operated distribution switches are not tested. Switch inspection is part of the Distribution Circuit & Equipment Inspection Program. | Need to “test” or operate distribution switches introduces the need to schedule that work during light load periods of the year. If alternate feed capability does not exist, switches will have to be jumpered, or planned outages will need to be taken. | $8M - $12M per year or 60 to 90 FTEs line effort. Additional, un-estimated, staffing would be needed in the dispatching setup area to write all the switching orders that would be needed. NOTE – These costs were not included in the original $75M cost estimate submitted to the PAPUC for all of the Pennsylvania EDCs. |
## Miscellaneous Items

<table>
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<tbody>
<tr>
<td>Plan Submission</td>
<td>EDC's submit a proposed comprehensive plan every 2 years; PUC must approve or reject plan; EDC must rewrite plan if rejected.</td>
<td>EDC's provide Commission with progress on completing work but Commission does not approve or reject work plan.</td>
<td>Unknown; FirstEnergy uses one set of maintenance plans for its operating Companies in Ohio, New Jersey, and Pennsylvania, allowing the efficient use of Corporate computer systems and enterprise wide approaches to meeting the Company's maintenance plans. Any significant changes to these Corporate plans could be a driver for state specific plans, requiring small to major computer systems changes, negating the savings achieved through synergistic programs.</td>
<td>Unknown, see comments to left</td>
</tr>
<tr>
<td>EDC's must submit separate plans for Urban areas vs. Rural areas as defined by US Bureau of Census</td>
<td>FirstEnergy does not differentiate between urban and rural areas with regards to the above maintenance plans.</td>
<td>The implication here is that there would be different maintenance plans for rural and urban areas; this would drive the need to prepare additional schedules, as well as changes to computer systems as detailed above. Elements of plans would also need to be reviewed as the defined areas are changed, with those elements in areas of change being moved from one maintenance plan to another.</td>
<td>Unknown, see comments to left</td>
<td></td>
</tr>
</tbody>
</table>