BEFORE THE
LONG ISLAND POWER AUTHORITY

IN THE MATTER of a Three-Year Rate Plan Case 15-00262

REBUTTAL TESTIMONY OF
TRANSMISSION & DISTRIBUTION
BUDGET AND OPERATIONS
PANEL

Date: June 4, 2015
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I. WITNESS QUALIFICATIONS AND DESCRIPTION OF TESTIMONY

Q. Please state the names of the members of this Transmission and Distribution (“T&D”) Budget and Operations Rebuttal Panel (the “Panel”).

A. We are John D. O’Connell, Nicholas J. Lizanich and Theodore G. Pappas.

Q. Have you previously submitted pre-filed testimony in this proceeding?

A. Yes, as members of other panels that have pre-filed testimony in this proceeding.

Q. What is the purpose of your rebuttal testimony?

A. We will address the testimony of the DPS Staff’s Transmission and Distribution Operations Panel (“Staff T&D Panel”) with respect to certain recommendations and expense reductions they have proposed concerning PSEG LI’s vegetation management and pole inspection programs and the staffing needs identified with the North American Electric Reliability Corporation’s (“NERC”) new definition of the bulk electric system (“BES”). Finally, we address the testimony of the DPS Staff’s EEP/REV Panel with respect to PSEG LI’s request for $900,000 of incremental costs for identifying REV alternative solutions in 2016, 2017, and 2018.

II. DISTRIBUTION TREE TRIM

Q. Are you familiar with the DPS Staff’s recommendations with respect to PSEG LI’s vegetation management program (“tree trim”) for LIPA’s electric distribution system?

A. Yes, we are. As part of this rate plan filing, PSEG LI presented budgets that increased tree trim funding to the level required to complete trimming on the whole distribution system within a four-year cycle based on a larger “box” for the tree trimming. This request results in a cost increase of $16.2 million in rate year 2016, $16.2 million in rate year 2017, and $6.2 million in rate year 2018. The DPS Staff
agreed with PSEG LI’s proposal to trim on a four-year cycle, acknowledging that the four-year cycle is consistent with industry best practices. DPS Staff also agreed with PSEG LI’s major increase in LIPA’s distribution line clearance specification starting in January of 2014. The new clearance is 300% larger than previously used by National Grid and is also in line with industry best practice. This combination of the specification change and trimming the distribution system on a four-year cycle will yield tangible reliability and operational benefits to our customers.

Q. Did the DPS Staff agree with the cost increases associated with the enhanced tree trimming practices that PSEG LI had implemented and with which the Staff agreed?

A. No, they did not. The DPS Staff reduced PSEG LI’s Distribution Tree Trim Budget by approximately $9.7 million in both 2016 and 2017.

Q. What was the basis for the DPS Staff’s disagreement with the tree trimming-related costs proposed by PSEG LI?

A. There were several reasons. As part of this rate plan, PSEG LI was seeking to perform additional trimming so it can complete its first four year cycle by the end of December 2017. This intensification of work is what accounts for the large increase in funding requested in 2016 and 2017. The DPS Staff, instead, recommended that trimming performed in 2014 and 2015 should not be associated with a specific cycle period. Instead, DPS Staff recommended that PSEG LI start an official four year cycle in January 2016. Although DPS Staff acknowledges that its recommendation will defer funding for remedial trimming, they claim that this change should not negatively impact reliability “because PSEG LI will continue to use the existing process to identify and prioritize which circuits to trim in the early years of the
cycle.” The DPS Staff also substituted the lower cost per mile associated with 2018 in PSEG LI’s submission for the higher costs PSEG LI estimated in 2016 and 2017, although those higher costs were based on our estimates of greater work in those years.

Q. Do you agree with DPS Staff's recommendation to commence a new four-year cycle on January 1, 2016?

A. No, we do not. Because PSEG LI already began a four-year cycle when it assumed operation of the LIPA system on January 1, 2014, it is not logical to begin a new cycle in 2016. While PSEG LI began a four-year cycle in 2014, in order to remain within the constraints of the rate freeze, only approximately 40% of the circuits will have been trimmed by the end of 2015. This is less than the 50% that would have been completed in two years of a four-year cycle. We are proposing to increase the circuit trim in 2016 and 2017 in order to have a full, four-year cycle completed by the end of 2017.

Q. DPS Staff admits that its recommendation will defer funding for remedial trimming, but claims that this should not negatively impact reliability because PSEG LI will continue to use the existing process to identify and prioritize which circuits to trim in the early years of the cycle. Do you agree that reliability will be unaffected?

A. No, we do not. Despite the fact that we would prioritize trimming under the DPS Staff proposal, the fact remains that, under the DPS Staff proposal, the complete system trim would take an additional two years. The two-year delay in completing the first cycle would result in significantly more tree related outages than would occur if we complete the cycle in 2017. The additional outages would occur under “blue sky” and storm conditions. Beyond the blue sky impact, we are concerned with the
effect of DPS Staff’s recommendation on storm reliability. Again, deferring the trimming cycle will result in reliability that is worse than it would have been had we done the trimming as proposed. But deferring the trimming will also result in additional storm damage, increased storm outages and increased storm cost, over what would occur under the proposed schedule. Under the tree trim proposals we have made, the LIPA distribution system would be fully trimmed to the new standard tree trim box by the end of 2017. Starting a new cycle in 2016 means that the LIPA system will not be fully trimmed to the new “clearance box” until the end of 2019. Consequently the system would be much more vulnerable to weather for an additional two-year period. We estimate that implementing the DPS Staff recommendations would result roughly in 50,000 more vegetation-related outages in the 2016-2018 period, with each outage affecting anywhere from a handful of customers to thousands of customers.

Q. Do you agree with the DPS Staff’s use of the lower cost per mile in 2018 for 2016 and 2017, as well

A. No. DPS Staff’s calculation is based on a significantly flawed assumption. PSEG LI’s 2016 budget for Distribution tree trim is $27.4 million, based on 2,722 circuit miles trimmed @ $9,600/mile, plus a 4% adder for tree removals. In contrast, DPS Staff assumed 2,200 circuit miles trimmed at a cost of $7,900/mile for a total cost of $17.7 million. The difference is DPS Staff’s adjustment of $9.7 million. It is noteworthy that the DPS Staff recognized that PSEG LI used a unit cost of $10,701 per mile and $9,527 per mile in 2014 and 2015, respectively. DPS Staff’s use of the
unit cost per mile of $7,889 from the 2018 budget and applying it to the cost per mile in 2016 and 2017, however, does not reflect that the 2018 cost per mile is lower solely due to the aggressive trim in 2014 – 2017 under PSEG LI’s proposal, which permitted a much less aggressive trim cycle to begin in 2018. Given the significant increase in line clearance implemented by PSEG LI beginning in 2014, there is a higher cost per mile to clear the primary lines the first time through the system (that is during the 2014-2017 four-year cycle proposed by PSEG LI) under the revised specification. This cost per mile increase is primarily due to the need to remove large diameter limbs (and the large increase in overall vegetation matter being removed), as well as doubling the cost of vegetative debris removal. Environmental Consultants, Inc. (“ECI”) data indicated similar cost increases for utilities that have significantly increased their clearance specification for the first time through the cycle under the revised specification. The $7,889 cost per mile forecast in 2018 is reflective of the savings that will only be realized once trimming begins its second cycle (and for subsequent cycles).

Q. Would it be appropriate to use the 2018 cost if DPS Staff’s new four-year cycle commencing in 2016 were adopted?
A. No. Again, as explained above, the approximate cost of $7,889/mile cannot be realized until all the primary distribution wire (approximately 8,850 circuit miles) is trimmed to the enhanced line clearance specification. Therefore, the cost of approximately $7,889/mile cannot be used for 2016 and 2017 – nor can it be used for 2018 unless the four year cycle is completed at the end of 2017, as proposed by PSEG
LI. The cost savings per mile projected for 2018 in the PSEG LI rate plan is based upon the completion of the four-year cycle trim of distribution system (approximately 8,850 circuit miles) using the enhanced specification from 2014 through 2017. Therefore, the $9.7 million annual distribution tree trimming reduction recommended by DPS Staff in 2016 and 2017 is not reasonable because it does not achieve the four-year cycle and is based on an unrealistically low cost per mile based on conditions that will not exist in 2016-2018 under their recommendation of a four-year cycle commencing in 2016.

Q. Does DPS Staff’s recommended revenue requirement for distribution system tree trimming support DPS Staff’s recommended four-year cycle?

A. No. DPS Staff’s recommended revenue requirement will fall well short of supporting even DPS Staff’s recommended four-year cycle. This is so because, as explained, the cost per mile of $7,889 used by Staff is reflective of a system that has been fully trimmed to the new specifications and 60% of the distribution system will not have been trimmed to the new specifications as of the end of 2015. Consequently, the aggregate annual revenue that DPS Staff would allow for trimming approximately 2,200 circuit miles (one-fourth of distribution system mileage) will not support that amount of vegetation removal. This, again, demonstrates why PSEG LI’s proposal to complete trimming to the new specifications by the end of 2017 is superior to embarking on a new, four-year cycle in 2016 before the system is fully trimmed. When the benefits in terms of greater system reliability under PSEG LI’s approach –
especially in storms – is factored in, the merits of PSEG LI’s proposed approach to
distribution system tree trimming become manifest.

III. TRANSMISSION TREE TRIM

Q. Are you familiar with DPS Staff’s observations and recommendations
concerning transmission tree trim?
A. Yes, we are. It does not appear that DPS Staff made any reduction to the
transmission tree trim budget. Nevertheless, DPS Staff made several observations
and recommendations.

Q. Do you agree with their observations?
A. No, we do not. For example, DPS Staff notes that PSEG LI stated the funding would
be used to shorten our transmission trim cycle from five to four years but opined that
they do not believe trimming on the proposed four year cycle is appropriate for
transmission lines of voltages including 69kV or 138kV. Staff’s position is that the
clearance widths should be much greater which, in their opinion, would lead to a
longer trimming cycle length. Staff also claims that it does not appear that PSEG LI
has cleared to the maximum widths along LIPA’s ROW.

Q. Is this a valid criticism?
A. No. In the first place, trimming to a four year cycle is a good industry practice.
Furthermore, DPS Staff’s claim that our clearing protocols are inadequate is
inaccurate. The majority of PSEG LI’s 69kV system (57%, or 330 of 579 circuit
miles) is located on municipal roads with anywhere from 150 to 200 trees per mile,
most of which are directly under the lines. To achieve strict adherence to a clearance
of greater than 18 feet would involve the removal of over 70,000 trees under these
lines. The municipalities and customers owning these trees would have to agree to
allow PSEG LI to remove these trees. Not only would this be cost prohibitive but, we
believe, would lead to significant negative customer response to that scope of tree
removal.

Given that many of LIPA’s transmission lines are located on narrow ROW’s
or easements in which the parcels are owned by municipalities (highway) or
customers themselves (rear property), PSEG LI trims to either an 18 foot clearance
(69kV and below) or a 25 foot clearance (138kV) specification. When a main trunk
of a healthy tree is located on a non-LIPA owned parcel, the balance of that tree is
directionally pruned away from the conductors as per ANSI A300 standards. A
directionally pruned tree has a very high probability of falling away from the
conductors if uprooted. A 2013 “Comparative Assessment of LIPA’s Vegetation
Management Program” performed by ECI (a leading provider of vegetation and asset
management consulting services to the utility industry), indicated in section 3.9 that
LIPA’s transmission line clearances were consistent with those specified by FERC
and NERC. Furthermore, prior to 2014 (while on a five-year average cycle), we
noticed that there was a need for more between cycle “hot spot trimming.”

Q. The DPS Staff also claims that PSEG LI’s response to IR DPS-TDP-0296
indicated that there were approximately 100 tree contacts, exclusive of
hurricanes, on transmission lines 69kV and above from 2010 to 2014, or an
average of 20 contacts per year, while other utilities in New York have less than
an average annual rate of 20 vegetation contacts per year. Based on the belief
that the LIPA system experienced more tree contacts, DPS Staff recommended
(Staff T&D Panel, at pp. 16-17) that:
in order for its ROW Vegetation Management Program to be on par with other utilities in New York, [PSEG LI] should embrace and put into effect Departmental regulations at 16 NYCRR Part 84 (Part 84), as well as, the practices contained in Cases 04-E-0822 and 10-E-0155, as applicable to PSEG LI and LIPA’s system. We believe that by the end of 2017, the full extent of all overhead 69 and 138kV transmission ROW rights should be documented and reported to the Department for review.

Please address this contention.

A. A re-examination of the 2010-2014 vegetation-caused transmission trip data reveals that catastrophic storm data was inadvertently included in the 99 trips identified. A revised dataset shows that Exhibit___(TDOP-REB-1) there were only 45 vegetation related trips from 2010-2014. For 2010-2012 the average vegetation trips were 12.6 per year. Focusing on the more recent data in the last year under National Grid, when a 25’ clearance for 138kV was fully implemented, as well as the first year of PSEG LI’s move to a four-year average cycle, the data shows a dramatic improvement to the point where a total of only seven trips occurred in 2013-14, resulting in average trips per year of only 3.5 – clearly as good, or better than the average for other New York electric utilities. Because the basis of DPS Staff’s recommendation (that PSEG LI has more vegetation-related trips than other utilities) is inaccurate, there is no need for the remedial action counseled by the Staff Panel and the recommendation should not be adopted. The recommendation that PSEG LI be subject to the DPS regulations and PSC orders regarding ROW management will subject PSEG LI and LIPA to unnecessary compliance cost without any demonstrated benefit. Furthermore, DPS Staff’s recommendation that ROW rights be documented and reported to DPS Staff
for review has not been justified and is superfluous. When necessary to determine
rights on a particular parcel to facilitate tree trimming or removal, that is easily
accomplished without the time consuming process called for in the DPS Staff
testimony. Given that tree contacts on the LIPA system are in line with, or lower
than, other utilities in the state, this would impose costs for no benefit.

Q. At pages 17-19, the DPS Staff Panel notes that PSEG LI proposes to spend $3.0
million in 2016 and $3.25 million annually for 2017 and 2018 for its Hazard
Tree/Storm Hardening program. Although Staff recommends approving the
requested funding levels, they further recommend that the funding level for
distribution remain at $1.1 million per year and that the additional remaining
proposed funding should be used to support tree removal for all transmission
line ROWs of 69kV and above until the further program enhancements, more
accurate costs and results become known and analyzed. Please address this
recommendation.

A. PSEG LI’s filing increased T&D hazardous tree removals from 2015 by an additional
$1.0 million for 2016 and $1.25 million for 2017. The maximum ratio of storm
hardening / hazard tree removals (transmission to distribution) for 2016 and 2017 that
is advisable is 40% to 60%. The rationale behind this is that, while trimming the
increased amount of distribution circuit miles (2,700 miles annually), line clearance
will identify a greater number of high risk hazardous trees that will require short term
action. Therefore, transmission related hazard tree removals annual spending for
2016 and 2017 should remain at approximately $1.2 million.

Q. Please sum up your views regarding the DPS Staff’s approach to transmission
tree trim.

A. We are gratified that the DPS Staff recommends no adjustments to the proposed
overall expenses for transmission tree trim. We further explained that hazardous tree
removals have already been increased as part of the filing. Finally, PSEG LI does not
agree that sacrificing the four-year transmission cycle and increasing tree removals is
the correct transmission vegetation management strategy for LIPA’s Long Island
transmission system.

IV. POLE INSPECTIONS

Q. Are you familiar with the recommendations of the Staff T&D Panel with respect
to pole inspections?

A. Yes. The DPS Staff notes (p. 20) that PSEG LI performs inspections on transmission
and distribution poles on an 11-year and 10-year cycle, respectively, and that the pole
inspections program involves two parts, a visual inspection and a physical integrity
test. DPS Staff also notes that PSEG LI has budgeted $3.2 million for pole
inspections in each rate year from 2016 to 2018. The DPS Staff, however, objected to
several aspects of our pole inspection program. First, DPS Staff believes that the
68,000 pole inspections proposed to be performed annually in the years 2016-2018 is
overly aggressive; second, Staff does not agree that bore inspections are needed as
often as currently being performed and third, DPS Staff believes that the costs of
inspection and treatment should be separated. Consequently, the DPS Staff has
proposed a reduction of approximately $2.11 million per year to PSEG LI’s pole
inspection program over the three-year rate plan period.

Q. Do you agree with the DPS Staff’s proposed changes to program and reduction
of the budgeted amounts for this activity?

A. No, for reasons we explain in detail below. Generally, our pole inspection and
treatment program is based on the fact that given the age of the poles on the LIPA
system, a more aggressive program of inspection and treatment protocol is more cost
effective at extending the life of poles and avoiding the high cost of new replacement poles. DPS Staff’s recommendation of a scaled-back inspection (46,500 poles versus PSEG LI’s recommendation of 68,000 poles) and treatment regime is not cost effective, as it does not support the effective inspections and treatments needed to extend the useful life of a pole. The effective inspection and treatment of poles greater than 20 years old on the LIPA system will require “excavate, sound and bore” type inspections which together will capture at least 80 percent of poles that are inadequate to remain in service.

Q. Please explain the reason why poles must be inspected and treated.

A. Poles are the foundation of the distribution and transmission systems and maintaining acceptable reliability performance without an adequate inspection and treatment program is not sustainable. PSEG LI would like to complete the inspection of all the poles in a less-than-ten-year period so as to complete the cycle early because there was a significant lag period from when the old inspection program was halted by National Grid in 2006 and re-started in 2012. We believe inspecting all poles sooner will minimize the reliability impact of having deteriorated poles left unaddressed longer. Our rate plan filing calls to accomplish this in a more aggressive eight year period, while giving recognition to certain budgetary constraints imposed as a result of the rate freeze in effect from 2013 to the end of 2015. Performing an annual inspection of 68,000 poles will allow us to stay on track to meet the inspection schedule, because the inspections for years 2012 to 2014 were significantly lower than the annual target of 35,700. PSEG LI believes making the investment now will
allow us to meet the demands of inspected poles recommended for re-inspection in
three to five years in this current cycle. Approximately two to three percent of annual
pole inspections that show initial signs of deterioration based on shell thickness will
be slated for re-inspection within three to five years.

The current inspection program addresses circuit locations with a high
percentage of poles greater than 20-years old. The information set forth in Table 1
below shows that performing visual, sound and bore type inspections is cost effective,
and is even more cost effective when chemical treatment is applied to those poles
showing signs of deterioration. The re-inspection cycle of poles with this type of
inspection is two to three years and with treatment the re-inspection cycle could be
eight to ten years. The annual budgeted amount of $3.2 million will cover the cost of
inspecting and treating the targeted population of poles greater than 20 years old.

Visual and sound inspections will find only the priority pole rejects (described
below), but will not find the additional 90 percent of pole rejects that show no visible
signs of deterioration. Visual and sound inspections also cannot identify the extent of
loss of strength due to internal decay. Distribution pole rejects are categorized in four
categories:

- Non-restorable rejects (deteriorated but can be scheduled for replacement)
- Priority rejects (requires immediate replacement)
- Rejects for re-inspection (re-inspection to be done in 3 to 5 years)
- Rejected for insufficient strength but suitable to be life extended with a steel
  truss
Because of the demonstrated limitations of visual and sound inspections, we have found bore inspections to be an integral part of the pole inspection process for poles that are greater than 20 years old. Bore inspection takes on a particular significance in LIPA’s case because the average age of a distribution pole on the LIPA system is 38 years. Bore inspection is particularly effective in locating decay in poles that is not visible externally on the pole. Over 60% of rejects (and 98% of replacements) were found due to bore inspections being performed during the 2014 pole inspection program. The use of the bore inspection method allows poles with a lower level of deterioration to be reinforced with steel trusses rather than being replaced at a much higher cost. Also, a shell thickness indicator is used to measure internal deterioration of the pole. The remaining shell thickness is used to schedule re-inspection of poles, usually within three to five years, that show initial signs of deterioration. The following Table 1 shows the efficacy of the various conventional wood pole inspection programs.
### Table 1. Efficacy of conventional wood pole inspection programs (adapted from Birtz 1997a, 1981).

<table>
<thead>
<tr>
<th>Type of inspection</th>
<th>Reinspection cycle</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>2. Visual, sonic and bore.</td>
<td>2 to 3 years</td>
<td>Finds 40 to 50% of the bad poles. Caution must be exercised or good poles with shake are thrown out. Should find most danger poles. Does nothing to maintain pole plant.</td>
</tr>
<tr>
<td>3. Visual, sound and bore.</td>
<td>2 to 3 years</td>
<td>Finds about 50 to 60% of the bad poles and most danger poles. Does nothing to maintain pole plant.</td>
</tr>
<tr>
<td>4. Visual, partial excavate, sound and</td>
<td>3 to 5 years</td>
<td>80 to 90% of rejects can be located. Fair inspection but does not prolong the life of pole plant.</td>
</tr>
<tr>
<td>bore.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5. Excavate 6 to 8 in. around entire</td>
<td>5 to 6 years</td>
<td>90 to 95% of rejects can be located. Good inspection and most of the poles that would fail early are treated. Usually treat about 20% of the older poles.</td>
</tr>
<tr>
<td>circumference, inspect and treat to 18</td>
<td></td>
<td></td>
</tr>
<tr>
<td>in. all poles with decay or defects.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6. Visual, excavate, sound, bore and</td>
<td>8 to 10 years</td>
<td>99% of all rejects are located. Most economical in long run as the life of the pole plant is extended.</td>
</tr>
<tr>
<td>groundline treat.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Q. Were the observations contained in Table 1 confirmed by PSEG LI’s actual experience?

A. Yes. We found that the majority of poles identified for replacement and reinforcement were identified as a result of performing sound and bore inspections. Table 2 shows the breakdown of poles recommended for replacement and reinforcement based on the 2014 pole inspection program:

<table>
<thead>
<tr>
<th>Inspection Type</th>
<th>Replacements</th>
<th>Percent Replacements</th>
<th>Reinforcements</th>
<th>Percent Reinforcements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sound &amp; Bore Reject</td>
<td>13</td>
<td>31%</td>
<td>43</td>
<td>32%</td>
</tr>
<tr>
<td>Sound Only Reject</td>
<td>1</td>
<td>2%</td>
<td>1</td>
<td>1%</td>
</tr>
<tr>
<td>External Treat Reject</td>
<td>0</td>
<td>0%</td>
<td>89</td>
<td>66%</td>
</tr>
<tr>
<td>Excavated, Sound &amp; Bore Reject</td>
<td>29</td>
<td>67%</td>
<td>1</td>
<td>1%</td>
</tr>
</tbody>
</table>

Table 2

Q. For context, please provide the breakdown and derivation of the cost of inspection and various methods of treatment used.

A. Tables 3 and 4 show a breakdown (per pole) of inspection costs versus treatment costs respectively, and Table 4A shows a summary of the 2014 pole inspection/treatment program categorized by line item, number of poles serviced and percentage.

<table>
<thead>
<tr>
<th>Inspection Costs</th>
<th>ITEM per pole</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>BORE</td>
<td></td>
<td>$7.55</td>
</tr>
<tr>
<td>EXCAVATE</td>
<td></td>
<td>$20.73</td>
</tr>
<tr>
<td>EXCAVATE, SOUND AND BORE</td>
<td></td>
<td>$36.78</td>
</tr>
<tr>
<td>PRIVATE PROPERTY (a pole that is located on land owned by non-governmental legal entities – i.e., non-public property. Poles located on private property usually have a barrier or fence and requires owner approval to get to.)</td>
<td></td>
<td>$7.77</td>
</tr>
<tr>
<td>SOUND AND BORE</td>
<td></td>
<td>$16.05</td>
</tr>
<tr>
<td>SOUND ONLY</td>
<td></td>
<td>$8.50</td>
</tr>
<tr>
<td>VISUAL VERIFICATION</td>
<td></td>
<td>$3.55</td>
</tr>
</tbody>
</table>
**Table 4**

<table>
<thead>
<tr>
<th>ITEM per pole</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>EXTERNAL TREAT</td>
<td>$7.72</td>
</tr>
<tr>
<td>SUPERFUME</td>
<td>$19.72</td>
</tr>
</tbody>
</table>

**Table 4A**

<table>
<thead>
<tr>
<th>Line</th>
<th>Description</th>
<th>Quantity of poles serviced in the 2014 inspection program [A1]</th>
<th>Percent of total number of poles serviced in the 2014 inspection program</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>LINE 320 - SUPERFUME PER POLE</td>
<td>1,661</td>
<td>79.3%</td>
</tr>
<tr>
<td>2</td>
<td>LINE 280 - EXC, SOUND AND BORE</td>
<td>1,076</td>
<td>51.4%</td>
</tr>
<tr>
<td>3</td>
<td>LINE 300 - SOUND ONLY</td>
<td>491</td>
<td>23.4%</td>
</tr>
<tr>
<td>4</td>
<td>LINE 290 - EXTERNAL TREAT</td>
<td>1,046</td>
<td>49.9%</td>
</tr>
<tr>
<td>5</td>
<td>LINE 310 - SOUND AND BORE</td>
<td>763</td>
<td>36.4%</td>
</tr>
<tr>
<td>6</td>
<td>LINE 330 - VISUAL VERIFICATION</td>
<td>91</td>
<td>4.3%</td>
</tr>
<tr>
<td>7</td>
<td>LINE 340 - PRIVATE PROPERTY</td>
<td>166</td>
<td>7.9%</td>
</tr>
</tbody>
</table>

Based on 2,095 poles inspected

The following Table 5 shows the breakdown of inspection costs versus treatment costs for the 68,000 poles based on 2014 inspection/treatment data line item percentages (Table 4A above).

As shown in the table, about 50 percent of poles will be excavated, sound checked and bored during the 2016 to 2018 inspection program. The treatment and inspection costs for each of those years will be $1,325,271 and $1,869,847.

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1 The percentages in Table 4A were derived from using the base 2,095 poles on the 2014 inspection program. These percentages will not add up to 100%. Each line item shows the service performed on a portion of the poles. Some poles could have one or more line item applied to them. For example on line 1 of the Table, 1,661 poles out of 2,095 received Superfume treatment, which is 79.3% of the poles in the 2014 program and so on. These line item percentages were applied to the 68,000 poles per year for years 2016 to 2018.
respectively, which results in a total of approximately $3.2 million, which is the annual budgeted amount.

Table 5
Proposed Breakdown of 68,000 Poles Per year to be inspected & treated (2016 to 2018)

<p>| Treatment costs |
|-----------------|-----------------|-----------------|-----------------|-----------------|</p>
<table>
<thead>
<tr>
<th>Line Item</th>
<th>Description</th>
<th>Unit Price</th>
<th>Using 2014 % line item breakdown</th>
<th>Quantity of poles (2016 to 2018)</th>
<th>Net Amount per Year (2016 -2018)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>LINE 320 - SUPERFUME PER POLE</td>
<td>19.72</td>
<td>79.3%</td>
<td>53,913</td>
<td>$1,063,167</td>
</tr>
<tr>
<td>4</td>
<td>LINE 290 - EXTERNAL TREAT</td>
<td>7.72</td>
<td>49.9%</td>
<td>33,951</td>
<td>$262,104</td>
</tr>
<tr>
<td>Total Treatment Costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$1,325,271</td>
</tr>
</tbody>
</table>

<p>| Inspection costs |
|-----------------|-----------------|-----------------|-----------------|-----------------|</p>
<table>
<thead>
<tr>
<th>Line Item</th>
<th>Description</th>
<th>Unit Price</th>
<th>Using 2014 % line item breakdown</th>
<th>Quantity of poles (2016 to 2018)</th>
<th>Net Amount per Year (2016 -2018)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>LINE 280 - EXC, SOUND AND BORE</td>
<td>36.78</td>
<td>51.4%</td>
<td>34,925</td>
<td>$1,284,544</td>
</tr>
<tr>
<td>3</td>
<td>LINE 300 - SOUND ONLY</td>
<td>8.5</td>
<td>23.4%</td>
<td>15,937</td>
<td>$135,464</td>
</tr>
<tr>
<td>5</td>
<td>LINE 310 - SOUND AND BORE</td>
<td>16.05</td>
<td>36.4%</td>
<td>24,766</td>
<td>$397,488</td>
</tr>
<tr>
<td>6</td>
<td>LINE 330 - VISUAL VERIFICATION</td>
<td>3.55</td>
<td>4.3%</td>
<td>2,954</td>
<td>$10,486</td>
</tr>
<tr>
<td>7</td>
<td>LINE 340 - PRIVATE PROPERTY</td>
<td>7.77</td>
<td>7.9%</td>
<td>5,388</td>
<td>$41,865</td>
</tr>
<tr>
<td>Total Inspection Costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$1,869,847</td>
</tr>
</tbody>
</table>

Q. DPS Staff suggests (at p. 24) that inspection and treatment costs should be separated because not all poles that are inspected receive treatments. Do you have a view as to this recommendation?
A. Although the cost of treatment can be separated from the cost of inspections this ignores the realities of the process. Crews that inspect poles, apply treatment at the same time to poles requiring treatment. It would be inefficient to have one crew inspect poles and another crew to return to treat them. This is why the costs are not
separated. Nevertheless, based on inspecting 68,000 poles per year for the 2016 to
2018 period, the treatment and inspection costs for each of those years will be
$1,325,271 and $1,869,847 respectively, which, as stated previously, results in a total
of approximately $3.2 million, which is the annual budgeted amount. The breakdown
of the costs between inspection and treatment, however, does not change the need for
the dollars expended on the pole inspection program, nor does it reflect the realities of
how the program operates or change the need to address the targeted population of
poles greater than 20 years old with the pole inspection program.

Q. The DPS Staff recommended (at p. 26) that the bore inspection and its associated
evacuation activities on distribution poles should only be performed when
absolutely necessary. They recommend using a unit cost that would allow for
visual and sounding inspections, which is $8.50 per pole. Do you agree with
these recommendations?

A. No, we do not believe that the DPS recommendations on “visual and sounding”
inspections are supported by good utility practice. Although it is true that the
“excavate, sound and bore” method is more expensive ($36.78 per Table 3) than the
visual and sound method recommended by the DPS Staff ($8.50), our methodology is
based on the fact that the average age of a LIPA-owned distribution pole is 38 years.
Consequently, the age of the poles on the LIPA system will require “excavate and
bore” type inspections along with treatment to retard future deterioration of the poles.
Again, the information shown on Table 1 demonstrates that “excavate, sound and
bore” type inspections together are quite effective and will capture 80 to 90 percent of
pole rejects. Although this type of inspection method is very effective at identifying
poles that are “at risk,” it does nothing to extend the life of the pole without proper
treatment. The DPS Staff’s recommended funding for preventive treatment of $697,404 is inappropriately low and should be increased so as to reach the levels of effectiveness explained above. Given the replacement cost per pole of approximately $6,500, the treatment cost is highly cost effective in comparison.

Q. Using the DPS Staff Panel’s recommended inspection levels of 46,500 poles per year to complete its 10 year cycle and unit rate of $8.50, they recommend expenses of $395,248 per year, versus PSEG LI’s budgeted amount of $3.2 million per year. Is this lower level of spending appropriate?

A. We do not believe this level of pole inspection is appropriate or consistent with good utility practice. As stated above, we intend to intensify the pole inspection program from 2016 to 2018 to account for inspection and treatment work not performed in prior years. We believe that the inspection of all poles must be completed in a less-than-ten-year-period so as to complete the cycle early because there was a significant period from when the old inspection program was halted in 2006 and re-started in 2012. Therefore, it is our plan to accomplish this in a more aggressive, eight-year period. Performing an annual inspection of 68,000 poles will allow us to stay on track to meet the inspection schedule. Making the investment now will allow us to inspect the poles recommended for re-inspection in three to five years in this current cycle.

Using the breakdown from the 2014 inspection results, it is expected that of the 68,000 poles to be inspected annually, about 35,000 will be excavated, sound and bore tested; 24,000 will be sound and bore tested; and about 53,000 poles will be treated. About 80 to 90 percent of poles identified to be replaced and 100 percent of
poles identified to be reinforced can be located when excavate type inspection is used with sound and bore inspections. Effective treatment of the pole will extend the service life of the pole by retarding the decaying process. This is a much more cost effective option than a cursory inspection, minimal treatment and then having to replace a pole at a cost of $6,500 per pole.

Based on the average age of 38 years for a LIPA owned distribution pole, about 37.5 percent of poles greater than 20 years will require excavation, sound and bore inspections and treatment to retard future deterioration of the poles. Poles that are treated will have their service life extended by 10 to 15 years. This will produce significant cost savings for customers for pole replacements in those years. Untreated poles will be recommended to be re-inspected in less than the ten-year inspection cycle.

Q. **Does the program identified by PSEG LI produce tangible benefits for the customers?**

A. Yes, it does. Although seemingly more expensive than the DPS Staff alternative, the comprehensive pole inspection program is quite cost effective, identifying poles that can be saved, rather than replaced, and extending their lives by more than a decade. Moreover, the program will provide greater reliability benefits by identifying deteriorating poles before they become a problem – either by failing and causing outages or by needing replacement. The DPS Staff’s recommendations would provide near term savings at a longer term greater cost.
Q. Finally, the DPS Staff notes (at p. 25) that PSEG LI indicated in your response to IR DPS-TDP-0183 that it inspects 324,771 LIPA owned poles and 22,287 customer-owned poles. DPS Staff then states that they “recommend the inspection program not apply to the customer-owned poles [and that] [t]his policy...is consistent with other New York utilities.” Please address this contention.

A. PSEG LI agrees that the inspection program should not apply to customer owned poles. In fact, however, since the pole inspection program restarted in 2012 (under National Grid), no consumer owned poles were selected to be inspected as part of the program so the recommendation has no practical effect on the budgeted amounts.

V. COSTS ASSOCIATED WITH THE NEW BES DEFINITION

Q. The DPS Staff T&D Panel notes (at p. 32) that PSEG LI identified the need for $900,000 of additional expenses in each rate year (2016, 2017, and 2018) to support its ability to perform maintenance and system analysis activities resulting from the new definition of the Bulk Electric System (“BES”). The Staff recommends cutting that spending in half, to $450,000 annually, based on its contention (at p. 34) that “the incremental staffing mentioned in response to IR DPS-TDP-394 should have been more fully justified.” Do you agree with the DPS Staff T&D Panel’s belief that cutting the annual spending amount in half will provide adequate funding levels for this mandated new activity?

A. No, we do not. We demonstrate below that the scope of the new responsibility is extensive and will require all of, and more than, the $900,000 funding increase in order to satisfy this new requirement.

Q. How did the BES definition change?

A. FERC Order No.773 approved a modification to the definition of the BES developed by NERC. This modification established a bright-line threshold that includes all facilities operated at or above 100kV. The definition also identified specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of the BES. The new definition also removed language that
allowed for regional discretion in defining BES. Entities have to be compliant with this new definition by July 1, 2016.

Q. How does this impact LIPA?
A. LIPA is the owner of the BES on Long Island which is operated by PSEG LI pursuant to the OSA. As a result of this new definition, the Service Provider, on LIPA’s behalf, identified 119 additional BES assets that will be subject to NERC’s mandatory reliability requirements. Prior to the FERC Order, one 345 kV line had been identified as a BES element under the old definition. The additional 119 total elements include lines, capacitors, series reactors, transformers and line terminals as BES elements. Prior to the FERC Order, LIPA was registered as a Transmission Owner (“TO”), Distribution Provider (“DP”), Load Serving Entity (“LSE”) and a PSE (“Purchasing Selling Entity”). The PSE function has been deactivated with an effective date back to March 19, 2015. As a result of the additional assets classified as BES, LIPA will be required to register as a Transmission Operator (“TOP”) and a Transmission Planner (“TP”) and is currently executing a Coordinated Functional Registration (“CFR”) agreement with the New York State Independent System Operator (“NYISO”) and the other New York State Transmission Owners. Registration as a Transmission Operator also requires LIPA to obtain NERC Certification with Northeast Power Coordinating Council (“NPCC”). An assessment of LIPA’s ability to be certified as a TOP is scheduled to be conducted in the third quarter of 2015.
Q. Please describe the additional work required by the BES definition change.
A. As a currently registered TO, DP, LSE, and PSE, there are 49 Reliability Standards and 354 requirements applicable to LIPA. As a TO, DP, LSE, TOP, and TP under the new definition, there will be 79 Reliability Standards and 531 requirements applicable to LIPA. These standards and requirements will now apply to an additional 119 BES elements.

Q. This appears to differ somewhat from the response to DPS-TDP-0394. Please explain why this is so.
A. With respect to the number of standards and requirements arising from the new BES definition, the response to DPS-TDP-0394 only addressed Transmission Operations. There is additional work necessitated by the new BES definition.

Q. Please describe the additional work.
A. In addition to the increase in applicable standards, LIPA, as a registered TOP, will be subjected to on site audits on a three-year cycle as opposed to off-site audits on a six-year cycle. Although LIPA is the NERC Registered Entity, PSEG LI, as the Service Provider, assists LIPA in meeting its compliance obligations under the NERC Reliability Standards. Within PSEG LI’s Transmission Operations, the incremental annual labor resource requirements are associated with one new position to meet System Personnel Training requirements, one Reliability Compliance Engineer as a result of the increase in applicable NERC Reliability Standard compliance obligations, and one Operations Engineer to assist the Control Room with day to day operations and managing the control room documentation process as a result of the increase in applicable NERC Reliability Standard obligations as a registered TOP.
Within Substation, Protection and Telcom (“SPT”) Operations, the incremental annual labor resource requirements are associated with one Reliability Compliance Engineer as a result of the increase in applicable NERC Reliability Standard compliance obligations.

Within Planning, the incremental annual labor resource requirements are associated with two additional system planners to perform newly identified studies required by a TP and to support Cross Functional Studies required by Operations due to the TOP designation, and one Reliability Compliance Engineer as a result of the increase in applicable NERC reliability compliance obligations.

Again, our plan is to use the $900,000/year to fund four of the above listed seven FTEs with the balance of the funding from savings in operations.

Q. Are these new staffing requirements incremental to the work that PSEG LI is currently doing?
A. Yes, the work described in this testimony is incremental only. It is new work required by the change in the BES Definition.

Q. What are the labor requirements?
A. Please see Exhibit___(TDOP-REB-2) for the details of the man-hours. The total incremental man-hours are 17,091 (14,942 management and 2,149 bargaining unit).

Without accounting for vacations and holidays, this equates to 7.2 management FTEs alone, or $1.55 million (at an average salary of $115,000 plus $100,740 in benefits, OPEBS and pension ). We asked for only a portion of this amount, $900,000 per year, with the intention that the balance, including funding for the bargaining unit employees, might be derived from internal savings. Consequently, we have both 1)
understated the request, and 2) factored in anticipated “productivity savings” that
might not be realized in arriving at our request of $900,000. DPS Staff’s proposed
reduction to a level of only $450,000 per year consequently appears arbitrary and
unsupported.

Q. Was the scope of the work discussed in the response to DPS-TDP-0394?
A. Yes, and for clarity we will restate the incremental work.

The following lists some of the incremental responsibilities to comply with
applicable NERC Reliability Standards for various T&D organizations:

1) Transmission Planner compliance responsibilities:
   a. Annual Transmission Planner Assessments for 2 year, 5 year and 10
      year cycles to support NERC TPL standard requirements including but
      not limited to N-l-1 analysis, simulation of contingencies with known
      system outages, simulation of relay loadability limits and extreme
      contingency analysis.
   b. Sensitivity analyses to the annual transmission planner assessment
      mentioned above as required by NERC Standard TPL-001-4.
   c. Dynamic stability analysis to support selection of dynamic
      contingencies.
   d. Annual Short Circuit Analysis for near term planning horizon.
   e. Study, propose and document corrective actions for TPL violations
      (these corrective actions need to be coordinated with neighboring TOs
      and ISOs if neighboring TOs are impacted).
   f. Annual evaluation, establishment and documentation of system
      operating limits (“SOL”) as per the FAC-014 standard in the planning
      horizon which is the thermal transfer analysis, voltage transfer analysis
      and stability transfer analysis for four internal interfaces.
   g. Coordination and communication of studies with NYISO and adjacent
      TPs such as Consolidated Edison.
   h. Documentation of study reports tailored towards the compliance
      requirements so that the compliance infrastructure is set up for on-site,
      off-site or spot audits.
   i. Development and documentation of Reliability Audit Worksheets
      (“RSAWs”) for each applicable reliability standard.
j. Support the upcoming new Geomagnetic Disturbance standard where there is a requirement to conduct vulnerability assessment of the near term transmission planning horizon once every 60 months.

2) Planning support for cross functional compliance responsibilities:
   a. Incremental work load in identifying and establishing operational system operating limits to support TOP standard requirements.
   b. Documentation and modification of seasonal operating studies as compliance evidence for operational requirements.
   c. Completion of RSAWs for applicable TOP standards for the areas where planning studies are utilized.
   d. Conduct studies to support protection standards such as PRC-002-2, PRC-023-3 and other standards such NERC Critical Infrastructure Protection (“CIP”).
   e. Coordination and communication of studies with cross functional organizations for compliance.

3) Transmission Operator compliance responsibilities:
   a. Track and maintain compliance with 200+ NERC Reliability Standards’ requirements.
   b. Manage a process to continually review requirements and prepare RSAWs associated with applicable Reliability Standards.
   c. Travel to attend NYISO Bulk Electric System/Transmission Operator monthly meetings.
   d. Consultant support for NERC compliant Operator training program design.
   e. System Operator Training and annual task certification requirements on a recurring basis.
   f. Maintain Transmission Operator NERC Certification credentials.
   g. Procure software solutions for managing certified operator training program, in an auditable NERC compliant manner. The software solution has a recurring annual cost with annual increases after initial licensing and setup fees.
   h. Document management support to maintain and control documents and procedures used to demonstrate compliance (change tracking, review cycles, etc.).
   i. Prepare for and respond to NERC operations and CIP audits. The Transmission Operator audit cycle is three years compared to the six year audit cycle for LIPA’s current registration.
4) Protection & Engineering related compliance responsibilities:
   a. Perform studies for system protection coordination with neighboring
      Generator Operators, Transmission Operators, and Balancing
      Authorities.
   b. Determine required Disturbance Monitoring points to ensure that
      adequate disturbance data is available to facilitate Bulk Electric System
      event analyses.
   c. Analyze Disturbance Monitoring data for events occurring during the
      reporting period.
   d. Determine Transmission and Generator Relay Loadability to prevent
      unnecessary tripping of generators during a system disturbance.
   e. Assist Transmission Operations to develop NERC/CIP documentation
      for critical facilities.
   f. Validate rating and methodology with neighboring utilities.
   g. Research and validate requirements and rating methodology for 138kV
      OH and UG circuits.
   h. Assist Transmission Operations on inventory of circuits for NERC
      compliance data requests.
   i. Determine overload ratings and associated methodology for 345kV and
      138kV transformers.
   j. Determine overload ratings and associated methodology for GSUs
      associated with NERC generators.
   k. Determine overload ratings for all substation components (e.g., bus,
      switches, and breakers) rated 100kV or higher. Periodically review
      industry standards and their applicability to the various BES
      components.
   l. Maintain the NERC associated data, the self-certification of compliance
      with the required standards, and participation in NERC workshops,
      meetings, and audits and data analysis of events occurring during the
      reporting period.
   m. Comply with System Protection Coordination (in drafting phase).
   n. Perform joint Planning and Engineering analysis on a per-BES-element
      basis in all BES substations for relay and communication redundancy
      and separation requirements.

5) Incremental Preventive Maintenance BES compliance responsibilities:
   The preventive maintenance increase associated with NERC BES will require
   additional testing, documentation and test guidelines for the following BES
   element protection relay system types:
   a. Relay communication systems associated with transmission line
      protection
   b. DFR/SER equipment
Q. Does the above-described scope of work validate your contention that the $450,000 per year recommended by the DPS Staff Panel for the new BES work is inadequate?

A. Yes. As we pointed out previously, the average, total cost of a management employee (salary and benefits) that would be assigned to do this work is approximately $215,740 per year. The $450,000 annual amount recommended by the DPS Staff would cover the cost of only slightly over two FTEs to perform all of this additional work. This is simply not possible. As we also noted, our request of $900,000 per year is conservative and will require PSEG LI to find well over $600,000 of additional productivity savings from MAST\(^2\) employees alone, not including any bargaining unit employees who would also be required to perform duties related to this additional work. The DPS Staff’s recommendation that all of this new work can be done by only two new people is unreasonable and should be rejected. The entire $900,000 amount identified for the considerable new work necessitated by the FERC/NERC mandated change in the BES definition is conservative and, if anything, significantly understated.

\(^2\) MAST employees are management, administrative, supervisory and technical personnel.
VI. INCREMENTAL COSTS TO IDENTIFY REV ALTERNATIVES

Q. Starting at page 32, line 15 of the Staff EEP/Rev Panel testimony, Staff addresses PSEG LI’s request for $900,000 of incremental costs for identifying REV alternate solutions in 2016, 2017, and 2018. Does Staff propose to adjust these costs?

A. Staff recommends that because engineering costs for the traditional solutions are already included in the project estimates, and the REV solutions will need to be at a lower cost than the costs of traditional solutions recommended to be funded, the $900,000 per year should be removed.

Q. Does PSEG LI agree with this conclusion?

A. No. As indicated in the response to DPS-TDP-0234, REV and Utility 2.0 type solutions require much more information and analysis than typical conventional solutions and thus result in incremental costs.

Q. How are studies associated with REV and Utility 2.0 solutions different than those required for conventional projects?

A. Typical conventional solutions do not require analysis of the makeup of the load relief. Those solutions, rather, are based on the maximum demand that must be satisfied. The conventional solution solves the design deficiency not just for the peak demand period, but is available to meet needs throughout the year. REV and Utility 2.0 solutions require additional information on specific hourly needs and customer characteristics that contribute to the demand, i.e., residential, commercial and industrial. In addition, the relief needed is affected by the sensitivity of the load of the proposed solution, e.g., if the solution is air conditioner control, then the amount of relief will vary by season and temperature. Distributed generation is also subject...
to more analysis. For example, solar production is affected by not just the hour of the
day, but the day of the year, since the number of hours of daylight varies between the
beginning and end of the summer period, i.e., from mid-June to the end September.
Even central heat plant options will vary with the customer’s thermal load profile
requirements. As such, additional work is required to identify the needs to be
satisfied by Utility 2.0 and REV projects and to incorporate those needs into the RFPs
and RFIs. The work just begins at this point, as evidenced by respondent requests for
more information in response to the RFI, which PSEG LI recently issued.
Exhibit___(TDOP-REB-3). Project analysis requires not just review by in-house
staff, but education of the potential RFI respondents. Even when implemented, the
control of these solutions will need to be integrated into the dispatch, requiring
additional analysis.

Q. Can the cost of these analyses be included as part of conventional project costs?
A. It can, but the issue is the need for additional staffing to perform the REV solution
studies in addition to more conventional T&D solutions. As noted above, REV
solutions necessitate more complex studies with numerous additional considerations.
Whether the cost is in the project cost or separately, the staffing is needed to support
the incremental additional REV solution study requirement, which necessitates
additional funding. The request is meant to identify the increased cost, which is not
otherwise reflected in the revenue requirement of the conventional project.
Q. Why can’t the cost be included in the ultimate solution, be it either conventional or REV?
A. The costs can be included once the solution is selected, be it conventional or REV. The additional REV analysis costs would be considered in the comparison of the REV and conventional solutions. As noted in the prior question, however, the funding is needed for the additional staffing and resources now required to perform the REV analysis work, regardless of whether the REV solution is actually implemented.

Q. Do you have any other comments regarding treatment of REV costs?
A. Yes. On page 31, the DPS Staff agrees with the inclusion of conventional capital costs as placeholders for conventional T&D solutions. The DPS Staff suggests, however, if a REV solution is selected, it can simply replace the funding from the conventional solution. It is not this simple because a conventional solution would be amortized over a longer period (e.g., 30 years) whereas a REV solution may be handled as an expense (not an asset) or have a shorter asset life than a conventional solution (e.g., smart meters have shorter asset lives than conventional meters), and recovered immediately or over a much shorter period of time than a conventional solution. This will result in different revenue requirements.

Q. Does this conclude your testimony?
A. Yes, at this time.