NEW YORK STATE OF OPPORTUNITY. Department of Public Service

125 East Bethpage Road, Plainview, NY 11803
www.dps.ny.gov/longisland

Audrey Zibelman
Chief Executive Officer

Kimberly A. Harriman
General Counsel
Kathleen H. Burgess
Secretary

September 28, 2015

Honorable Ralph Suozzi
Chairman
Board of Trustees
Long Island Power Authority
333 Earle Ovington Blvd.
Uniondale, New York 11553

Re: Case Matter 15-00262 – In the Matter of a Review and Recommendation Regarding a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC.

Sent Electronically

Dear Chairman Suozzi:

It is my pleasure, as CEO of the New York State Department of Public Service to submit to the Long Island Public Authority Board of Trustees the Department's recommendation concerning the three-year rate proposal for electric rates and charges submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC (PSEG LI).

This submission of the three-year rate plan represents another successful step in the improvements to utility operations and cost containment contemplated by the LIPA Reform Act. The New York Legislature enacted the Reform Act on June 20, 2013 to address the financial, structural and operational deficiencies of LIPA that became apparent in the aftermath of Superstorm Sandy. In just over two years, many of the positive changes that were contemplated in the Reform Act have been achieved, including the establishment of the DPS Long Island Office, which is now providing independent, comprehensive oversight of electric operations for the first time in LIPA's history. In addition to the rate review that is the subject of this letter, the DPS is now involved in reviewing the same key aspects of utility operations as it does for all other major electric utilities in the State, including storm preparedness and response, consumer complaint mediation, operational audits, capital plan reviews, and review of metrics and the company's performance under the metrics.

As you are aware, the Reform Act authorized the modification of the Operating Services Agreement (OSA) to shift more operational control from LIPA to PSEG LI. Following the Board of Trustees approval of the modified OSA, PSEG LI assumed operational control on January 1, 2014. The transfer of operational control from National Grid was successful and reflected months of planning and preparation by both utilities and LIPA. As a consequence, PSEG LI was able to immediately begin full operations of the system, successfully demonstrate its operating skills through several significant storms, and meet its service metrics. Importantly, the Reform Act delivered on its promise to keep delivery rates on Long Island unchanged since 2013. Moreover, the effective transition also allows PSEG LI to direct its attention over the next three years to further improvements in utility operations and customer service, including implementing the changed operations contemplated in PSEG LI's 2.0 plan as part of the State's Reforming the Energy Vision initiative.

The Department's recommendation recognizes the unprecedented investment in system hardening and resiliency initiatives. The $730 million FEMA grant to LIPA will be leveraged by a $73 million capital investment in these activities, financing of which is recognized in the attached Rate Recommendation. These activities, both FEMA and ratepayer funded, will include elevation of critical infrastructure above forecasted flood plains and construction of over 300 circuits to improved design standards, which will also incorporate some associated level of tree trimming.

Finally, by pursuing the additional securitization authorized by the Legislature earlier this year and approved by the Board in June, LIPA will significantly reduce its debt expense. Rates have been stabilized on Long Island due in large part to the tax reforms and highly effective debt restructuring authorized by the Reform Act. It is estimated that the Reform Act's securitization authorization and tax reforms will save ratepayers $720 million over the next three years, including $172 million in lower debt payments from the next securitization.

A key element of the Reform Act, as recognized in the OSA, is the requirement for PSEG LI and LIPA staff to submit to DPS their proposal for a three-year rate plan for years 2016, 2017, and 2018. That provision ensures that the delivery rates established for Long Island are considered through the rigors of an extensive and public review process. On January 30, 2015, PSEG LI and LIPA staff proposed to raise rates by a cumulative sum of $441 million over three years.

In accordance with the Reform Act, the Department's review and recommendations are designed to ensure that the Authority and the Service Provider provide safe and adequate transmission and distribution service at rates set at the lowest level consistent with sound fiscal operating practice and other criteria set forth in the Act. In developing our recommendations, certain principles were of paramount importance, such as minimizing the burden on consumers and supporting sound investment in the infrastructure, and preserving and improving the financial health of the Authority (*e.g.*, by reducing LIPA's historically high debt burden).

In setting rates for utilities, the Department's first responsibility is to ensure the utilities can provide safe and reliable service to their customers. To that end, we review the utilities' revenue requests to ensure that revenues are sufficient to meet this obligation and that they have an opportunity to earn a fair return for their investors. At the same time, because utilities are monopolies and not subject to the rigors of competition, the Department plays an important role in driving utilities towards efficiencies to ensure that ratepayers are not unduly financially burdened. This is the traditional standard for investor owned utilities in the State, but its spirit is also embodied in the Public Authorities Law requirement that LIPA maintain the lowest achievable rates. While PSEG LI as the provider of operations service and management to LIPA does not earn a rate of return, the company does have an opportunity to earn incentive compensation for achieving certain metrics that are affected in part by its operations budget. Therefore, we view the revenue requirement proposal filed by PSEG LI with a lens similar to the one we apply to the regulated utilities.

The Department has been responsible for the review of revenue requirements for investor owned utilities for over 100 years. The type and quality of the information that is required in a Department rate review, in addition to institutional knowledge of the participating parties and companies, results in a robust record to support final rate recommendations in our cases. In that tradition, the Department applied the same process of review to the PSEG LI rate case. In addition to applying its own regulatory expertise, the record benefited from the rigors of the rate review processes. Through eight months of review, including six public statement hearings, comments from thousands of ratepayers, two days of evidentiary hearings, four rounds of briefing and hundreds of pages of expert testimony from the parties in the case, DPS Administrative Law Judges, advised by a panel of the best technical experts at the Department (Senior Advisory Group), issued a draft recommendation which reduced PSEG LI's initial revenue requirement proposal by 26 percent, from a cumulative revenue requirement increase of $441 million over the three years, to $324.6 million.

The attached Rate Recommendation adopts for the most part the draft recommendation of the Senior Advisory Group, and recommends a three-year cumulative revenue requirement increase of $325.4 million, which still equates to a 26 percent reduction of PSEG LI's initial request. This recommendation reflects a balancing of competing interests and statutory and contractual requirements. Where there was insufficient support in the record to increase certain budgets as PSEG LI proposed, we recommend reducing those requested increases to a level that our experience and the record support (*e.g.*, Bulk Electric System, Distribution Tree Trimming, Outreach and Education). In other cases, where actual cost information was not available during the case, but where we know there will be a need for cost recovery (*e.g.,* interest rates on debt restructuring, labor costs that emerge from future collective bargaining agreements, etc.), the rate recommendation provides for updates for specific elements – subject to our review – to reflect actual costs before rates are set for each rate year. Overall, we have evaluated the total revenue requirement to be provided under the proposed Rate Plan and determined that, while PSEG LI did not prevail on each element of its case, it would receive sufficient revenues to operate the electric system in a prudent manner.

Equally important, as required by the Reform Act, the Rate Recommendation is consistent with ensuring that revenues are sufficient to satisfy the Authority's obligations with respect to its bonds, notes, and all other contracts. Included in these obligations is the OSA, the contract by which PSEG LI operates the electric system and by which its success is evaluated through the performance metrics included in the OSA.

As always in rate cases, there were competing expert opinions and credible and well-reasoned arguments. I commend the parties for their commitment to providing the best record basis to set rates that reflect the need to ensure ratepayers pay no more than necessary for electric service, while affording PSEG LI a reasonable opportunity to achieve contract performance metrics.

The revenue requirement for utilities falls into two categories: known costs and revenues and those that are uncertain and need to be forecasted based upon best available information and standard regulatory methodology. When looking at the forecasts of costs and revenues, the benefit of the doubt goes in favor of forecasts that do not unduly burden ratepayers, especially where the forecasted item has a mechanism to reconcile the forecast to actuals.

The Rate Recommendation addresses the budgets for operations and maintenance and capital expenditures, the forecast of revenues, and rate design matters. With respect to the first, the Rate Recommendation balances the need to provide sufficient revenues associated with outreach and education and system maintenance (*e.g.*, tree trimming and pole inspection) with the need to moderate rate increases. With respect to the second, the sales forecast represents an application of standard regulatory methodologies that comport with forecasts of economic improvement on Long Island. The Rate Recommendation notes that any under or over forecast of sales will be reconciled in the Revenue Decoupling Mechanism. Lastly, the rate design proposals were viewed with the eye towards mitigating customer impact, acknowledging the on-going evolution of rate design thinking in the Reforming the Energy Vision proceeding underway at the Public Service Commission, and the ability of customers to take responsive actions.

More importantly, the Rate Recommendation, if adopted by the Board, will ensure that critical investments are made to preserve and improve electric service and system resiliency and ratepayers realize the savings provided through debt securitization. For example, the Rate Recommendation supports the revenue requirement associated with completion of distribution tree trimming to an expanded area for the entire system by the end of the rate plan and implementation of the industry best practice of a four-year cycle thereafter. In addition, the Rate Recommendation provides revenues sufficient to complete pole inspections and necessary remediation and preventative actions within a time period consistent with industry best practices.

While nobody desires rate increases, it is important to note that a significant portion of revenues collected by rates are for items outside PSEG LI's control. For example, 25 percent of the non-fuel/purchased power revenues goes toward satisfying LIPA's property tax obligation. It is noteworthy that LIPA's property tax burden is among the highest of the State's utilities and well above the national average. Moreover, while LIPA is aggressively managing its debt obligations, 30 percent of non-fuel/purchased power revenues goes towards satisfying debt obligation and coverage requirements associated with financial metrics (*e.g.*, bond ratings). As noted, this percent would be materially higher if not for the ability of LIPA to securitize a significant portion of its existing debt authorized by the Legislature. Thus, while these non-controllable costs confirm the need to carefully scrutinize controllable expenditures, they also support the recommendation that when all factors are considered, the recommended rate adjustments are appropriate and should be adopted.

In summary, the attached Rate Recommendation will enable PSEG LI to provide reliable electric service to Long Island customers while being afforded an opportunity to earn performance based compensation and will continue the path of the Authority towards improved financial positions through lower debt costs and better debt ratings. The Department stands ready to address any questions the Board may have regarding the Rate Recommendation.

Respectfully submitted,

Audrey Zibelman
Chief Executive Officer

cc: Jon Mostel, Secretary, LIPA Board of Trustees

Encl.

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

MATTER 15-00262 – In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC.

DEPARTMENT RATE RECOMMENDATION

(September 28, 2015)

TABLE OF CONTENTS

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

MATTER 15-00262 – In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC.

DEPARTMENT RATE RECOMMENDATION

INTRODUCTION

On January 30, 2015, PSEG Long Island, LLC (PSEG LI or the Company) and the Long Island Power Authority (LIPA or the Authority) Staff submitted a three-year rate plan (for 2016 through 2018) for review by the Department of Public Service (DPS or the Department). The filing was the first rate filing made in accordance with Public Service Law (PSL) §3-b and Public Authorities Law (PAL) §1020-f, provisions enacted under the LIPA Reform Act (LRA) of 2013. Pursuant to the LRA, LIPA was reorganized, so that day-to-day operations were placed under the direction of PSEG LI, with LIPA focused on financing and overseeing the December 31, 2013 Amended and Restated Operating Services Agreement that exists between LIPA and PSEG LI (the OSA).[1] The new statutory framework calls for DPS to conduct a rate proceeding and provide the LIPA Board of Trustees (BOT) with a recommendation on rates for 2016, 2017 and 2018 (Rate Plan or Rate Proposal), with the final decision on rates being made by the LIPA BOT. This document constitutes the Rate Plan recommendation.

[1] Prior to January 1, 2014, a subsidiary of KeySpan had operated LIPA's electric system pursuant to a Management Services Agreement. Under the newly enacted statutes and as reflected in the OSA, on January 1, 2014, PSEG LI began operating under a new business model and operational plan, assuming operational and policymaking responsibilities that are more expansive than those of its predecessor.

PSEG LI was chosen to operate and manage the electric system on Long Island due to its broad experience as a top tier utility service provider. The revision to the relationship between PSEG LI and LIPA, as discussed above, was the result of an extensive examination of the LIPA structure following Superstorm Sandy and determination that structural improvements were necessary. The Department’s Rate Plan recommendation is premised on an understanding of (1) the revised structural relationship between PSEG LI and LIPA, (2) the contractual requirements governing this relationship, (3) the service standards and operating requirements applied to New York utilities, and (4) the applicable statutory requirements of the Public Authorities Law and the Public Service Law.

Specifically, the Rate Plan recommendation applies the Department’s experience in overseeing New York’s utilities and the standards that it uses to set revenue requirements and rates to forecasting PSEG LI’s capital needs and related financing costs, expenses and revenues. At times, PSEG LI has expressed concern that application of this knowledge may be at odds with its ability to earn incentive compensation under its service contract with LIPA. PSEG LI has expressed a belief that the revenue requirements and associated rates must be set at a level that is sufficient for it to conduct operations and have a reasonable opportunity to achieve the incentives contemplated by the OSA. According to PSEG LI, in the event that the LIPA BOT accepts a revenue requirement that fails to provide this opportunity, it will violate the terms of the OSA.

There is no real disagreement over the standard to be applied in this proceeding. The LRA is clear; the revenue requirements for PSEG LI must be set at the lowest achievable price while providing safe and adequate service and supporting sound fiscal operation of the Authority. In determining this level, the LIPA BOT must be mindful of the customer oriented performance levels contemplated within the OSA and set revenues at a level that provides PSEG LI with sufficient revenues to meet its contractual obligations. The Department's recommendations for the Rate Plan are consistent with these legal and contractual requirements and will enable PSEG LI to continue to provide improved electric service to Long Island ratepayers.

After considering the entire record, including the positions expressed on exceptions, the Department recommends that LIPA set rates designed to increase revenues by $30.4 million in 2016, $77.6 million in 2017 and $79.0 million in 2018.[2]

BACKGROUND

PSEG LI and LIPA Staff proposed rate increases of $72.7 million, $74.3 million, and $74.3 million for the years 2016, 2017 and 2018, respectively, for a cumulative increase in revenues of $441 million. At these proposed levels, LIPA's overall electric revenues, including power supply costs, would increase by approximately 2.0 percent each year. Looking solely at the impact on delivery revenues, the increases for 2016, 2017 and 2018, would be approximately 3.9 percent, 4.0 percent, and 4.0 percent, respectively.

Several procedural aspects of PSEG LI's rate filing are unique. First, it was not presented based on a traditional cost-of-service model with an actual historic test year, as would be the case to set rates for an investor-owned utility, but rather was prepared using the cash based Public Power Model and prospective budget information. Second, under the statute,

---

[2] Appendix I to this final recommendation is a schedule reflecting the revenue requirement effect of our proposed resolution of all contested issues.

the Department is required to review the Rate Proposal and make its recommendation to the LIPA BOT within 240 days,[3] or by September 27, 2015.[4]

As soon as the proposal was filed, trial staff designated to represent DPS (DPS Staff) immediately commenced its review, and other interested individuals, corporations, organizations, state and municipal entities intervened as parties.[5] DPS Staff and other parties engaged in extensive discovery, and, ultimately, LIPA Staff and PSEG LI responded to over 600 information requests.[6] Administrative Law Judges (ALJs) were assigned to rule on requests for party status, establish the procedural schedule and facilitate the orderly processing of this matter and conduct the public statement and evidentiary hearings.

By ruling issued February 3, 2015, the ALJs invited the parties to confer on the proposed scope of issues to be addressed in this matter. An initial procedural conference,

---

[3] The process thus differs from the 11-month rate case process for a typical investor owned utility under the Public Service Law.

[4] September 27, 2015 falls on a Sunday; thus, by operation of law, the time for performance of this statutory obligation is extended until Monday, September 28, 2015. See General Construction Law §25-a.

[5] In addition to PSEG LI, LIPA, and DPS Staff, other parties included the Utility Intervention Unit, Division of Consumer Protection, NYS Department of State (UIU); the City of New York (NYC); Caithness Energy, L.L.C.; the Retail Energy Supply Association; the Independent Power Producers of New York, Inc.; Thomas Bjorlof, *pro se*; the Honorable Michelle Schimel, NYS Assembly Member; Clara Kudder, *pro se;* International Brotherhood of Electrical Workers Local 1049; Nassau County; the Natural Resources Defense Council (NRDC); NRG Energy, Inc.; the Town of Brookhaven; the Suffolk County Comptroller (SCC); and the Suffolk County Legislature (SCL).

[6] Many of the information requests propounded by the parties were multi-part.

immediately followed by a technical conference, was held on March 3, 2015, on Long Island, in Smithtown. During the procedural conference, proposals regarding the schedule, scope of issues to be addressed, requests for party status, and other procedural matters were discussed. During this same week, as discussed in more detail later, a series of four public statement hearings were held at various locations on Long Island.

By rulings issued on March 12 and 30, the schedule and scope of issues for this matter were established. DPS Staff and intervenors pre-filed direct testimony responsive to the rate filing on May 14, 2015.[7] DPS Staff provided updates to its testimony in early June 2014, and the schedule was modified slightly to allow additional time for parties to file rebuttal testimony and exhibits responsive to DPS Staff's updated testimony. Rebuttal testimony was filed by PSEG LI, LIPA Staff, Nassau County, and NRDC throughout the period June 4-June 10, 2015.

Evidentiary hearings were held on June 23 and 24 in Smithtown, Long Island. Numerous parties actively participated in the evidentiary hearing, which resulted in the creation of a transcript with over 1,500 pages of testimony and cross-examination and the admission into the record of 139 exhibits. Initial post-hearing briefs were filed by LIPA Staff; PSEG LI; DPS Staff; Thomas Bjurlof, *pro se*; Nassau County; NYC; SCC; NRDC; UIU; the Town of Brookhaven; and a late submission, filed

[7] Intervenor testimony was filed by Thomas Bjurlof, NYC, the Suffolk County Comptroller, and NRDC.

by SCL.[8] Post-hearing reply briefs were filed by LIPA Staff; PSEG LI; DPS Staff; NYC; and the Town of Brookhaven.[9]

On August 21, 2015, the Draft Department Rate Recommendation (DDRR) was issued. The DDRR was prepared by Michelle Phillips, Administrative Law Judge; David Van Ort, Administrative Law Judge; Kimberly Harriman, General Counsel; Elizabeth Liebschutz, Chief Administrative Law Judge; John Scherer, Deputy Director, Accounting, Audits & Finance; Michael Worden, Deputy Director, Electric; this group is collectively referred to here as the Senior Advisory Group. As reflected in the DDRR, the Senior Advisory Group concluded that rates should be based on revenue requirements that increase by $28.786 million in 2016, $78.493 million in 2017, and $81.267 million in 2018.[10] Pursuant to the Notice of Process for Exceptions that was attached to the DDRR, parties were permitted to file briefs on and opposing exceptions, on Thursday, September 3, and Friday, September 11, 2015, respectively. Briefs on Exceptions (BOEs) were filed by NYC, DPS Staff, LIPA Staff, PSEG LI, Town

[8] When requesting party status both SCC and SCL stated that they were representing Suffolk County. However, as indicated herein and in their briefs, the Comptroller and the Legislature, were, in fact, representing disparate County interests and thus should have been listed as separate parties. As of July 22, 2105, the Document Matter and Management (DMM) party list was updated to reflect this distinction.

[9] An e-mail sent by the ALJs on July 21, 2015 at 3:53 pm, notified all parties that any objections to the lateness of SCL's brief were due on Monday, July 27, 2015. No objections were received, and SCL's brief was accepted for filing.

[10] See DDRR, Appendix 1.

of Brookhaven and SCL.[11] Briefs Opposing Exceptions (RBOEs) were filed by DPS Staff, LIPA Staff, and PSEG LI.

APPLICABLE LEGAL STANDARD

The parties devoted a considerable portion of their arguments in this case to issues such as PSEG LI's burden of proof, the quantity and quality of evidence in the record to support a rate determination, and the relationship among this rate proceeding, the LRA, and the OSA. The DDRR set forth the applicable legal standards at the outset of the document. No party disagrees with the statement of the applicable provisions of the LRA, but the parties interpret those provisions differently to reach different conclusions.

Under the statutory framework, the purpose of the Department's review is "to make recommendations designed to ensure that the authority [LIPA] and the service provider [PSEG LI] provide safe and adequate transmission and distribution service at rates set at the lowest level consistent with sound fiscal operating practices."[12] The statute further requires that the Department's recommendations be "designed to be consistent with ensuring that the revenue requirements related to such rate review are sufficient to satisfy the authority's obligations with respect to its bonds, notes and all other contracts" and shall not include any recommendation that "would modify the compensation or fee structure included within the operations services agreement."[13] These standards govern the DPS review of

---

[11] LIPA Staff states that it takes no exceptions to the DDRR's recommendations but is providing comment and clarification on several topics (LIPA Brief 2, 4). SCL similarly discussed several topics in its September 3rd brief but took exception to very few.

[12] PSL §3-b(3)(a)(i).

[13] PSL §3-b(3)(a)(ii-iii).

the arguments and positions that have been articulated by the parties on this record.

In several instances in this case, DPS Staff, sometimes supported by other intervenor parties, proposed adjustments that would decrease PSEG LI's revenue requirement and therefore its budget for rate setting purposes, asserting as the basis for the adjustment that PSEG LI had failed to establish a need for the full amount requested. DPS Staff and other parties often referred to this as PSEG LI's failure to meet its burden of proof. For its part, PSEG LI argued before the ALJs that certain adjustments to its proposed expense budgets are foreclosed by the OSA and the LRA (e.g., PSEG IB, pp. 6-9, 82-86, 99-104), but the DDRR disagreed, adopting the DPS Staff adjustments as reductions to the level of revenue requirements to be recommended.

On exceptions, PSEG LI clarifies that it recognizes a role for the DPS rate review, and sought only to make the point that if a DPS recommendation contravenes the LRA or the OSA it cannot be adopted. Nevertheless, PSEG LI claims that because it is not an Investor-Owned Utility (IOU), the procedural and substantive constructs used to regulate IOUs do not automatically apply, and must yield if and where their application would be inconsistent with either the LRA or the OSA. PSEG LI argues that the relationship between PSEG LI and the LIPA BOT established in the OSA is fundamentally different from the situation of an IOU and contains contractual obligations and rights that are not present for those utilities (PSEG BOE, pp. 2-8).

PSEG LI contends that the DDRR defaulted to traditional New York State Public Service Commission (PSC) ratemaking conventions that are either irrelevant or antithetical to the OSA arrangement. It asserts that, "[i]n the context of a budget review of this particular nature and under the LRA, the notion of an evidentiary burden of proof has no place" (PSEG BOE, p.5). DPS must explain why it believes a particular budget item has not been sufficiently supported, PSEG LI argues; otherwise, the DPS recommendation would merely substitute the Department's judgment for PSEG LI's, assertedly in contravention of the LRA (Id.). PSEG LI argues that the OSA and LRA preclude, in particular, the DDRR's recommended reduction of PSEG LI's customer outreach budget, its adoption of DPS Staff's productivity and inflation adjustments, and its treatment of pensions and OPEBs (PSEG BOE, pp. 1-11).

LIPA Staff, contrary to PSEG LI's position, states that an evidentiary burden applies to PSEG LI. It notes that the OSA and the LRA explicitly contemplated an evidentiary hearing and review process, adding that PSEG LI's responsibilities under the OSA include "rate case preparation, participation and *prosecution* before the DPS ..." (OSA § 4.2(A)(2)(e) [emphasis added]) and responsibility "for providing evidentiary and other support for all information in the Three Year Rate Plan" (OSA § 6.2(E)) (LIPA RBOE, p. 2).

LIPA Staff also says it does not share PSEG LI's view of the interaction between the DPS adjustments and the OSA. It argues that the establishment of an overall revenue requirement that differs from the PSEG LI proposed budgets is not tantamount to dictating utility line item budget spending. Rather, consistent with the OSA, PSEG LI will maintain broad discretion to manage its resources, without any dictates of what it must spend on any particular category of costs. As a result, says LIPA Staff, it is not possible for a particular adjustment to per se violate the OSA, adding that what accords with the OSA is "a reasonable opportunity," not a guarantee, for PSEG LI to meet its metrics and earn the incentive compensation available under the OSA.

LIPA Staff also states that it is hard to credit the notion that the total revenue requirement proposed in the DDRR does not afford PSEG LI a reasonable opportunity to meet its metrics, adding that PSEG LI has introduced no evidence or argument to that effect. LIPA Staff states its expectation that PSEG LI will operate within its approved budgets, but it notes that the OSA permits PSEG LI to spend up to 2 percent above budget and still have opportunity to earn all performance metric incentive payments (LIPA RBOE, pp. 2-5).

DPS Staff states positions that accord with those of the LIPA Staff. It argues that, contrary to PSEG LI's claims, its recommendations are in accordance with and in furtherance of the LRA and OSA, and that the metrics are a means to an end rather than an end in themselves. DPS Staff highlights that a fundamental objective of the LRA -- to increase transparency and provide for review by the DPS in a manner consistent with proceedings associated with rate proposals made by IOUs -- was realized here. It adds that, as with IOU rate reviews, in those instances where PSEG LI has failed to support its request, while having ample opportunity to timely develop the record to adequately support its proposals, those requests should be denied (DPS RBOE, pp. 2-10).

The points raised are important and deserving of a clear statement. The Department takes very seriously its mandate under the applicable statutes, which includes an obligation to respect the provisions of the OSA. In the largest sense, the OSA contemplates that through PSEG LI’s management, Long Island customers will have the opportunity to enjoy top tier utility services. Under the OSA, PSEG LI is entitled to fixed and variable compensation, the latter tied to a strong incentive arrangement based upon performance metrics. At the same time, and to ensure that customers are not paying too much for this quality service, the LRA commands that "rates are set at the lowest level consistent with sound fiscal operating practices."[14] The Department recommendation adheres to this statutory and contractual framework. This recommendation preserves PSEG LI's opportunity both to recover expenditures associated with the management and operation of the system and to achieve the metrics pursuant to which it earns incentive compensation, but it does so subject to the overarching statutory mandate to make sure rates are set at the lowest level necessary to achieve these goals.

Though there are differences between the financial structures of PSEG LI and LIPA and IOUs, when it comes to determining whether their required revenues are sufficient to meet their operating and service obligations the inquiries and examination that must be made are more alike than different. Both public and IOUs operate in a monopoly environment, where customers have no choice regarding the delivery of electricity through the wires and poles connecting them to the grid. Regulatory oversight provides a critical substitute for the effective competitive forces of a market, which could act to ensure efficient operations and maintain fair prices. The Department has considerable experience and expertise in such regulation, in particular, in assessing the need for and appropriate level of expenditures to provide electric utility services. Part of that expertise is the ability to make judgment calls when a balance must be struck among competing objectives of fairly compensating the provider for service and keeping rates as affordable for customers as possible.

[14] PSL §3-b(3)(a)(i).

Once rates are set, the IOU has a strong incentive to operate efficiently, since it simply keeps some or all of the revenue it receives over and above its actual cost of providing service. PSEG LI, in contrast, is compensated differently; hence the need for the metrics in the OSA that provide a substitute incentive to efficiently and effectively manage and operate the electric system. This difference in how PSEG LI and IOUs earn returns once rates are set should not obscure the strong and identical incentives they have during the rate-setting process, however. That incentive is to forecast budgets and rates that err in favor of minimizing the risk that they will not achieve their metrics, as the best means to ensure they can perform the tasks for which they are responsible and receive full compensation. This is very consistent with the natural bias of a utility to seek rates at a level that provides the highest opportunity to earn the allowed return. In both instances, strong scrutiny by an experienced regulatory body is essential to assure that the rates are set at a level to provide a fair opportunity to achieve the desired level of earnings, but not guarantee them. In assessing the evidence, the Department must apply its experience and independent judgment. We cannot simply accept forecasted expenditures "as is" simply because they may pertain to the OSA. To the contrary, as the LIPA Staff points out, because the OSA expressly states that, "[i]n any proceeding before the DPS, ... the Service Provider (i) shall be responsible *for providing evidentiary and other support for all other information in the Three Year Rate Plan*",[15] PSEG LI must provide sufficient record support for information concerning its portions of the rate plan proposal. Where the Department finds that the weight of evidence does not support a specific request, we still have the obligation to determine the level of

[15] OSA, §6.1(E)(1)(b)(i)(emphasis added).

revenues necessary to meet the utility’s capital and operating needs without overburdening consumers. As stated by the Senior Advisory Group, the recommended revenues in the DDRR protect Long Island consumer interests, consistent with the need to provide contractually afforded compensation to PSEG LI to provide safe and adequate electric service (DDRR, p. 6).

Such judgments are entirely consistent with the Department’s role under the LRA and the OSA. As was stated in the DDRR, the LRA charges DPS to ensure that the rates recommended to the LIPA BOT are sufficient to satisfy LIPA’s obligations "with respect to its bonds, notes and all other contracts,"[16] and the OSA is one of those “other contracts.” While DPS recommendations must not contravene that contract, the Department must properly rely on its expertise and judgment in assessing the weight of the evidence in order to formulate and present its recommendations to the LIPA BOT concerning the appropriate level of LIPA's rates and charges (DDRR, pp. 5-6).

The Department clarifies that a finding that PSEG LI has not met its burden to justify a given element of its rate increase request is not at all the same as finding that the record is insufficient. The arguments by Nassau County and Brookhaven that asserted failures of PSEG LI or DPS Staff to create a sufficient record in general require the Department to recommend a complete rejection of all requested rate relief are not supported by the record and must be rejected. The process followed here included the extensive exchange of information (i.e., hundreds of written discovery questions and numerous exchanges of technical information, including the formal technical conference and phone calls between and among various parties and their expert witnesses) and two days of evidentiary hearings that produced a hearing record in excess of 1,500 pages

16 PSL §3-b(3)(a).

of transcript and with over 130 exhibits. This process resulted in a record that is robust and more than allows the Department to meet its obligation to make recommendations to the LIPA BOT as required by the LRA (DDRR, pp. 6-7).

Brookhaven renews the same arguments on exceptions. PSEG LI and LIPA Staff respond that Brookhaven's exception should be denied. Both PSEG LI and LIPA Staff detail the transparency of the process that was followed and the sufficiency of the record that was created here (LIPA RBOE, p. 11-12; PSEG RBOE, pp. 15-16). They both note that Brookhaven chose not to exercise any of the numerous opportunities that were made available to it to actively participate in this process or to contribute to the record. They therefore assert that Brookhaven's complaints have no merit and should be rejected. We concur.

PUBLIC COMMENTS

Public Statement Hearings

A total of 29 individuals provided comments at the four public statement hearings held during the first week of March 2015. Of those statements, four statements were made by the International Brotherhood of Electrical Workers Local 1049 (IBEW) and three were made on behalf of the American Association of Retired Persons (AARP). The IBEW stated that it supports the proposed rate increase. It noted that PSEG LI has made investments, for example in tree trimming and technology, that have improved storm hardening and the reliability of the electric system, allowed the company to respond more quickly to storm outages and improved customer satisfaction. AARP commented that although PSEG LI's plans to fund programs to increase electric system reliability are laudable, the impact of the proposed electric increase on fixed income customers could be severe. It also argued that there is a need for an independent advocate to represent the interests of Long Island customers, and that without such an advocate ratepayers are not equally represented against the well-funded utility industry. Several people voiced support for a greater use of solar energy usage and energy efficiency measures to reduce the amount of electricity produced from fossil fuel. One individual, however, alleged that PSEG LI is moving too fast on a planned solar farm project because the energy it will produce will cost about $350 million more under a long-term contract than would otherwise be paid if the energy is purchased on the open market.

The Nassau County Comptroller joined with other speakers in criticizing the PSEG LI rate request because of an alleged lack of initiatives designed to improve productivity and reduce costs through technological innovations. He and others also argued that the 80-foot-tall poles being installed are destroying the quality of life on Long Island. One speaker complained that new poles are treated with the chemical pentachlorophenol, or "Penta," a known carcinogen. The individual recommended that the poles be wrapped to a height of four feet to prevent children from touching them. A few homeowners expressed concern over the use of smart meters, one resident alleging that the meters emit wireless radiation which is as a health concern for young children and people with implanted medical devices.

Written Comments Submitted

The Department received over 4,000 written comments in this matter. The vast majority of comments were form letters, the apparent product of two separate campaigns, one by AARP and the other on behalf of the residents served by Leisure Village Association (Leisure Village), Leisure Knoll Association (Leisure Knoll) and Leisure Glen Homeowners Association (Leisure Glen) (collectively, "Leisure Association"). Virtually all of the individuals stated their opposition to the proposed rate increase.

On May 8, 2015, the Director of AARP for New York State submitted a letter to the Secretary requesting that the comment period in this matter be extended to September 1, 2015 to give AARP time to collect written public comments from AARP members residing within the LIPA service territory. On June 10, 2015, the Secretary issued a letter extending the comment period until August 1, 2015. Approximately 1,600 letters were received as a result of AARP’s urging the public to complete and submit a form letter posted on its website. The letters state the proposed increase would put a strain on household budgets, and that Long Island customers are already paying among the highest utility rates in the country.

On May 29, 2015, the Leisure Association Board President filed a letter with over 1700 attached letters -- signed by residents of Leisure Village, Leisure Knoll and Leisure Glen -- all of which oppose the electric rate increase. Leisure Village, Leisure Knoll and Leisure Glen are retirement communities located in Ridge, New York. These were in addition to over 50 letters submitted separately by residents of these communities. The Leisure Association President points out that despite most of the Association’s members’ having made energy efficiency improvements to reduce energy consumption (insulation, appliances and lighting) under the Long Island Lighting Company and LIPA energy efficiency programs over the past eight years, the electric rates keep escalating. The Board President suggests that a separate reduced electric rate should be established for senior citizens. The Leisure Association members' letters question the need for a rate increase, particularly, a few members add, since fuel prices have been low for some time. The residents also echo the AARP position that existing rates are already among the highest in the nation. Other Leisure Association members questioned the extent to which there have been efforts to reduce PSEG LI's capital and operating costs. A number of the residents identify as a primary concern the potential adverse impact of the proposed increase on senior citizens and others with fixed incomes, and the increasing difficulty for them to continue managing expenses and living on Long Island. Lastly, several members echo support for the assignment of a consumer advocate to represent the interest of senior citizens.

Other written comments filed in this matter reiterate concerns raised at the public statement hearings, in particular criticizing PSEG LI's installation of taller utility poles as a storm hardening measure and the treatment of the poles with the PENTA chemical. A few argue that the ongoing costs to ratepayers for the Shoreham Nuclear Power Plant are a heavy burden on customers and that it is time to stop charging ratepayers for those costs. A few customers claim that the service provided by PSEG LI has not been an improvement over the service LIPA was previously responsible for. The Town Board of Smithtown submitted a letter in which it agrees with comments made by the Suffolk County Comptroller. In it the Town Board questions why residents do not have an independent utility consumer advocate and whether the rate increase is necessary. It states that delivery changes will increase as much as 26 percent during winter and 8.8 percent during the summer through 2018 and that residents are moving off Long Island because of the PSEG LI rate request. It suggests that PSEG LI consider implementing a time-variant pricing pilot to provide savings opportunities for customers.

Several State Senators submitted a letter, on July 30, 2015, raising concerns over the proposed rate increase. The letter questions, first, the use of a cost recovery mechanism that would allow automatic pass-through of energy supply charges which they questioned as being in the public interest. It further states that there is a general lack of information about the potential impacts on ratepayers, particularly senior citizens and the disabled, regarding the operation of the revenue decoupling mechanism. Finally, the letter says the LRA was expected to produce a reduction in LIPA debt and that the Legislature did not agree to creating the Utility Debt Securitization Authority merely to allow LIPA to refinance existing debt but, rather, to rein in LIPA's overall debt and reduce pressure on rates.

Opinion Line Comments

There were more than 2,900 comments received on the DPS Opinion Line regarding the pending rate matter. For the most part, the messages are consistent with the statements made at the public statement hearings and in the written comments. Most voice strong opposition to the proposed electric rate increase. Many note that they are retired senior citizens on fixed incomes and cannot afford a 12 percent rate increase. And, several assert that the rate increase may force them to move off Long Island.

Comments of AARP

In addition to providing comments at public statement hearings, AARP submitted a comprehensive, 42-page document on June 30, 2015, in which it states that affordability problems resulting from deteriorating economic conditions make it difficult for LIPA’s low income senior citizens to pay their electric bills. According to AARP, the proposed electric rate plan would unduly burden low-usage residential customers through increased delivery rates, approximate doubling of basic service charges by 2018 and shifting the burden for financial shortfalls (e.g. sales and revenues, storm costs, power supply costs and debt service coverage) from LIPA and PSEG LI to the LIPA customers.

In support of its claims, AARP alleges findings and statistics gathered from various resources, including:

- LIPA customers pay the third highest rates for electric service of the 144 largest electric providers in the 48 contiguous states.
- Roughly 10 percent of Nassau County’s 287,000 senior citizens and about 12.5 percent of Suffolk County’s 330,000 senior citizens are low income.
- More than 250,000 or 25 percent of LIPA customer households earn less than the approximate $58,000 annual statewide median income; and more than 160,000 or about 18 percent earn less than $35,000 annually.
- Average residential customer arrears have been increasing since 2009 and, as of the end of last year, more than 130,000 or 12 percent of residential customers were in arrears more than 60 days.
- Average deferred payment agreement (DPA) balances have increased 20 percent since 2009 and the aggregate amount of residential accounts subject to DPAs is about $65 million.
- Public Assistance to LIPA service area senior citizen households has increased from 2009 to over 84 percent in 2013.
- As a result of the proposed increases in the basic service charges, low-usage customers at usage levels of 500 kWh per month would experience increases of 6 percent per year on the delivery portion of their electric bills and a 10 percent increase on the total bill. The low-usage customers averaging 250kWh per month usage would experience at least 30 percent annual delivery increases and 17 percent increases on the total bill.

AARP maintains that it is imperative that the Department address these issues in the final recommendation to the LIPA BOT.

In addition to arguing that the current PSEG LI rate plan proposal should be rejected, AARP offers several recommendations for consideration. First, it agrees with DPS Staff that basic service charges should be frozen while the REV Track Two proceeding evaluates whether current rate design could be modified to better achieve the State's energy efficiency goals. Second, AARP proposes that the LIPA annual low-income program funding be increased from $3 million to $12 million, in accordance with a straw proposal presented by Department staff in Case 14-M-0565, to ensure that the energy burden of low-income customers is limited to no more than 6 percent of their household income. Third, AARP asserts that the existing LIPA revenue decoupling mechanism (RDM) be rejected and that the delivery service adjustment (DSA) be capped annually at $15 million, because they may result in large customer bill surcharges without Public Service Commission review. It notes that the RDM adopted by LIPA on April 1, 2015, outside of this rate proceeding, has not been subjected to a thorough review similar to the process accorded RDMs for investor owned utilities, and RDM adjustments can be triggered for reasons outside of management's control, such as weather or general economic conditions. As for the DSA, AARP emphasizes that there is no limit on ratepayer exposure for power supply costs in excess of budgeted amounts; ratepayers would have to shoulder the costs for all major storms, with the exception of $10 million of annual costs imprudently or unreasonably incurred or those denied for recovery by the Federal Emergency Management Agency (FEMA) because of actions taken in violation of FEMA standards; and debt service coverage is similar to equity

infusion that should be the responsibility of the corporate entity, not ratepayers. Finally, AARP says that there needs to be a more transparent examination of ratepayer bill impacts resulting from adoption of Utility 2.0 projects, which, it says, are likely to cost over $400 million to LIPA customers.
We have kept these comments in mind as we have addressed the contested issues discussed below.

CONTESTED ISSUES

Procedural Matters

The DDRR contains a finding that Nassau County's procedural arguments concerning the timing of discovery responses from PSEG LI and the ALJs' denial of its request for adjournment of the evidentiary hearings lacked merit.[17] This finding was made because: (1) Nassau County obtained formal party status in this case in March and was thus fully aware of and subject to all the ALJ rulings regarding process and schedule in the case; (2) Nassau County's lack of compliance with the ALJs’ instructions for handling discovery and preparations for the hearing in this case had been fully documented on the record (Tr. 947-54); (3) the ALJs made efforts to provide Nassau with alternative means for making its case (Tr. 5, 947-54); and (4) though Nassau County had used the word “prejudice” in its initial brief, it did not actually explain

---

[17] DDRR, pp. 15-16. Nassau County also asserted that PSEG LI did not contact the County as promised. The Senior Advisory Group stated that determining whether PSEG LI promised to contact the County or whether PSEG LI, in fact, attempted to contact the County does not assist the DPS in formulating the rate recommendations that it must present to the LIPA BOT and it does not provide sufficient bases for denying the requested rate increases. However, the Senior Advisory Group noted that good communication between PSEG LI and the County is important and encouraged PSEG LI to take all steps necessary to facilitate such communication (DDRR, p. 15, fn. 19).

how it has been prejudiced in this case, nor did it make an offer of proof as to what it might have established on cross examination or how an adjournment would have contributed to any different outcome in this proceeding (Id.). Nassau County did not take exception to the finding.

Sales Forecast

The total electric sales forecast is the sum of the forecasts for residential sales, commercial and industrial (C&I) sales, and other sales in the LIPA service territory. PSEG LI forecasted total electric sales of 20,268 Gigawatt hours (GWhs) for 2016, 20,255 GWhs for 2017, and 20,230 GWhs for 2018. In its revised testimony, DPS Staff forecasted total electric sales of 20,419 GWhs for 2016, 20,306 GWhs for 2017, and 20,226 GWhs for 2018 (Tr. 356). The difference between the forecasts is 151 GWhs in 2016, 51 GWhs in 2017 and 4 GWhs in 2018 (Tr. 356); the delivery revenue impact of these differences equates to ($12.5) million in 2016, ($5.3) million in 2017 and $1.0 million in 2018 (Exh. 76). PSEG LI and DPS Staff do not agree on the outcome of each other's residential models, and they disagree on both the methodology and outcome of their respective C&I models and on the total that should be forecast for other sales.[18]

In developing its residential sales forecast, PSEG LI created an econometric model using six independent or explanatory variables (cooling degree days (CDD); the ratio of employment to residential customers; median real home price; annual average real price of electricity; real regional income per customer; and real gross metro product per customer), then made an out-of-model adjustment to account for the anticipated reductions due to demand side management (DSM) or energy efficiency initiatives (Tr. 308, 315). It used a similar

[18] The Other Sales forecast accounts for 3 percent of the total sales forecast (Tr. 306, 393).

process to create its C&I sales forecast, except that it created econometric models for each sector that forms the C&I group, summed the results to get the overall C&I sales forecast, and then made out-of-model adjustments to account for the anticipated reductions due to DSM and cogeneration (Tr. 317-21). The other sales forecast was created using trend analysis of estimates provided by the customers in that category, and no out-of-model adjustments were made to this forecast (Tr. 322-23). PSEG LI developed its customer forecasts based on trends in population growth (Tr. 325-26).

DPS Staff utilized econometric time series models that combined regression analysis with time series analysis to forecast residential and C&I sales and number of customers (Tr. 356-58). DPS Staff's residential sales model is a per customer use model, using four explanatory terms (real price of electricity, per capita real personal income, CDD, and heating degree days (HDD)) and including a leap year adjustment variable and an autoregressive term (Tr. 365). DPS Staff's C&I sales model is sales per customer, adjusted for a leap year factor, utilizing as explanatory variables real electricity price, real gross metropolitan product (GMP) for Long Island, CDDs, and a dummy variable to capture the effect of Super Storm Sandy of 2012 (Tr. 375). DPS Staff modeled the number of households to generate its residential customer forecast and used employment as the economic driver in forecasting C&I customers (Tr. 377-78). DPS Staff accepted PSEG LI's other sales forecast as a starting point, but then updated the other sales forecast for each year to reflect the difference between 2014 actual sales and 2014 forecasted sales of 4,985 MWh (0.8 percent) (Tr. 335, 393).

PSEG LI's witness generally acknowledges that DPS Staff's use of a single model for residential sales forecast is "appropriate" (Tr. 341), however, PSEG LI argued that DPS Staff's total forecast, generally, and C&I sales forecast, in particular, are unrealistically high and overly optimistic. PSEG LI asserted that DPS Staff's C&I sales forecast is flawed because it is based on a 2015 forecast that is "demonstrably too high" as compared to weather normalized sales reported for LIPA's booked sales for 2014; would require exceptionally large and recently unprecedented annual growth levels to achieve; and did not account for sales results from January to May 2015, even though the DPS Staff forecasts were updated in June 2015 (PSEG IB, pp. 22-24).

PSEG LI stated that its C&I model, which utilizes eight NAICS (North American Industrial Classification System) sector models, is preferable to the single model approach used by DPS Staff, because it appropriately captures the differences in energy use intensity of the different customers/businesses that are represented in the C&I sector. In response to DPS Staff's assertions that the PSEG LI models fail to satisfy various important econometric tests, PSEG LI argued that such technical disputes about econometric models ultimately must give way to real world results. It noted that, after using the same general configuration of one residential and eight NAICS sector regression models for 15 years, its witness “can report a mean absolute percent error (MAPE) of [only] 1.1%," a forecast accuracy level that compares favorably to that of the Energy Information Administration (EIA) and the New York Independent System Operator (NYISO) during overlapping periods (Tr. 343).

DPS Staff said it updated its forecast for corrections identified by PSEG LI with respect to the commercial and industrial sales data (Exh. 140, p. 6). It argued that its updated C&I forecast should be adopted because it is based on billed sales and produces results that are consistent with historical data. DPS Staff added that its results are produced using a model which, unlike the Company's models, pass important and standard econometric tests, such as autocorrelation and multicollinearity tests (Tr. 369-74). DPS Staff explained that failure to pass the autocorrelation test calls into question the reliability of the Company’s forecasts. DPS Staff further explained that the failure of the multicollinearity tests indicates that some of the Company’s C&I models included economic variables that were too closely related, thereby resulting in inaccurate estimates and unreliable results (Id.). DPS Staff stated that its model includes key economic variables such as electricity price, CDD, and real GMP for Long Island (Tr. 374-76). Finally, DPS Staff argued that the forecasted economic growth of Long Island for the next two years is significantly higher than the previous recent years and that DPS Staff’s forecast is in line with the optimistic economic forecast for the Long Island economy (DPS IB, p. 8).

Based on the foregoing, which is repeated from the DDRR (pp. 15-18), adoption of the DPS Staff's sales and customer numbers forecasts was recommended. The DDRR noted that a Revenue Decoupling Mechanism (RDM) was approved by the LIPA BOT in the Spring and stated that the RDM will address and account for the differences between forecast and actual sales (DDRR, p. 19).

The DDRR addressed each of the specific components of overall sales as well as the forecast of customer numbers. With respect to the residential sales, it noted that DPS Staff's residential model and forecast uses 10-year CDD and HDD inputs, while the Company's model did not include HDD as an input and used 30-year average of annual CDD (Tr. 308-09). It recommended DPS Staff's model because use of the 10-year average CDD and HDD inputs properly puts more weight on recent weather data, which better captures the weather trend and continued climate changes, and is consistent with recent Commission decisions concerning sales forecasts.[19]

With respect to C&I sales, the DDRR recommended DPS Staff's C&I model (DDRR, pp. 19-20). First, it observed that DPS Staff incorporates 10-year CDD inputs, while the Company, when it uses such a variable, uses 30 years of data (Tr. 349-50, 379-80) and did not explain why its models sometimes lack a weather variable and/or a price variable. Second, it expressed concerns with respect to the level of out-of model adjustments that were made by PSEG LI to account for DSM. The DDRR noted that PSEG LI’s DSM savings are estimated based on evaluation reports, the targets of LIPA’s existing Energy Efficiency and Renewable programs, and changes in building codes and appliance standards. It observed that DPS Staff's DSM adjustments were more reflective of the fact that it takes time for the full effect of DSM initiatives to be reflected and even more time for the impacts of new building codes and standards to show up in electricity usage. And, as stated in the DDRR, the Senior Advisory Group approved of DPS Staff's decision to reflect PSEG LI's cogeneration adjustments as proposed (Tr. 392-93).

Additionally, the Senior Advisory Group was not persuaded by PSEG LI’s accuracy/MAPE argument. It noted that, as reported in the DDRR, DPS Staff addressed why the MAPE comparison to EIA was inapposite and unreasonably impacted by the PSEG LI calibration process; explained that neither the EIA nor NYISO forecasts for Long Island use a calibration process that is comparable to the process PSEG LI uses; and noted that EIA and NYISO forecasts are long term energy forecasts, whereas

[19] DDRR, p. 19, citing, as an example of a recent PSC case, Case 10-E-0362, Orange and Rockland Utilities, Inc. - Rates, Order Establishing Rates for Electric Service (issued June 17, 2011), p. 11.

the PSEG LI forecast is a short term forecast. DPS Staff also observed that PSEG LI's accuracy analysis is only performed for the "next-year" but that any accuracy must be performed for the following two to four years to verify and update the forecasting history to demonstrate whether meaningful indicators exist and that the forecast is valid (Id.). In light of the foregoing explanations, the Senior Advisory Group was not inclined to rely on the asserted accuracy of PSEG LI's forecasts as a basis for their adoption.

Finally, with respect to the other sales forecasts, the DDRR noted that DPS Staff accepted PSEG LI's other sales forecast as a starting point, then updated it to reflect 2014 actual sales, resulting in a delta of 4,985 MWh (0.8 percent) each rate year (Tr. 335, 393). It recommended DPS Staff's other sales forecast because it more appropriately reflects and accounts for actual data and experience (DDRR, p. 20).

PSEG LI takes exception, arguing that the DDRR should have adopted PSEG LI's sales forecast in its entirety. PSEG LI reiterates its position that a forecasting model cannot be fairly judged without analyzing the reasonableness of the predicted results against actual experience. It asserts that DPS Staff's C&I sales forecast is simply too optimistic. PSEG LI asserts that the record is clear that DPS Staff's C&I sales forecast contradicts the historical trend by producing an unrealistically high level of sales growth that has never before been seen by LIPA. PSEG LI states that the DDRR ignores this recent experience, noting that PSEG LI's position has been bolstered by the recent June and July sales in the C&I sector, which provide further evidence that its C&I year-to-date weather normalized sales results are tracking significantly closer to the Company's forecast than to DPS Staff's forecast. PSEG LI adds that the larger variance expected in DPS Staff's forecast for 2015 will carry forward into the DPS Staff's forecast for 2016-2018.

Thus, PSEG LI reiterates its initial brief position, saying that, in the end, technical disputes about econometric models ultimately must give way to real world results. It again notes that courts have long noted the futility of relying on forecasts that differ from actual results ("Experience -- how much better this is than expert testimony, whether dealing in history or prophecy." Bronx Gas & Elec. Co. v. Maltbie, 271 N.Y. 364, 375 (1936) (citing Willcox v. Consolidated Gas Co., 212 U.S. 19; City of Knoxville v. Knoxville Water Co., 212 U. S. l; Cedar Rapids Gas Light Co. v. Cedar Rapids, 223 U.S. 655, 669)), adding that more recent opinions are to the same effect: "The law is well-settled that the Commission may not rely on a reckoning when actual experience is available and establishes that the predictions have been substantially incorrect." Rochester Gas & Elec. Corp. v. Pub. Serv. Comm'n, 64 A.D.2d 345, 349-50, 410 N.Y.S.2d 142, 145 (1978), *aff'd*, 51 N.Y.2d 823 (1980), citing New York Tel. Co. v. Pub. Serv. Comm'n, 29 N.Y.2d 164, 169, 324 N.Y.S.2d 53, 55, 272 N.E.2d 554, 556 (1971).

PSEG LI argues that attempting to mitigate the results of any error in picking the DPS Staff sales forecast by noting, as does the DDRR, that the RDM "will address and account for the differences between forecast and actual sales" (DDRR, at 19) is "no reason to choose that inaccurate forecast." PSEG LI believes that its forecast will prove more accurate in the 2016-2018 period and argues that the ultimate rate increase that will be experienced when the RDM accounts for the differences between forecast and actual sales will lead to decreased customer satisfaction.

DPS Staff, in its brief opposing exceptions, points out that PSEG LI has completely ignored its criticisms of the flawed specification of PSEG LI’s econometric forecasting models, instead focusing solely on the results and accuracy of DPS Staff’s econometric models. DPS Staff contends that PSEG LI's argument that the "the larger variance" in Staff’s 2015 forecast will be carried forward to 2016-2018 forecasts is overstated. DPS Staff notes that while the forecasts submitted by it and PSEG LI are considerably different for 2016, they are almost identical by 2018. DPS Staff observes that the trajectory of its sales forecast is a 1% decline for the 2017 and 2018 rate years, while PSEG LI’s forecast holds sales flat, slightly declining by 0.1% each year, adding that by 2018, the forecasts reflect a difference of less than 0.3 percent. DPS Staff asserts that this convergence of forecasts reveals the fallacy of PSEG LI's "carry forward argument," adding that, if valid, PSEG LI's criticism would apply equally to its own 2018 forecast. DPS Staff also asserts that PSEG LI's RDM argument also falls apart as the 2018 forecasts converge.

Next, DPS Staff addresses PSEG LI’s comparison of Staff’s forecast to "actual" 2015 results. DPS Staff argues that it forecast annual, rather than monthly, sales, "in part to avoid making the very type of unstable billed sales to booked sales calibration adjustments that the Company must make to arrive at its estimate of 'actual' monthly sales." DPS Staff stresses that the 2015 sales presented by PSEG LI are not truly known actual sales, but rather are calibrated actual sales. DPS Staff indicates its agreement that a “real world” comparison of the DPS Staff and Company forecasts to actual sales is appropriate, but says that it should be performed using actual <u>annual</u> billed sales, and not PSEG LI's “calibrated” estimates of monthly sales. DPS Staff also argues that PSEG LI's attempt to "calibrate mismatching monthly billing cycles with the months for which those sales are booked result in a level of extraneous information which inhibits the identification of what is actually driving sales, i.e., the important economic variables which are correctly incorporated into [DPS Staff's] forecasting models."

Sales forecasts are the product of econometric modeling that is based on predicting the future values of numerous input variables that affect energy usage and statistically estimating coefficients that are applied to those variables. The accuracy of any forecast is, of course, dependent upon the accuracy of the prediction of those input variables and the minimization of statistical bias in the estimation of the coefficients. The determination of what particular assumptions and variables are most appropriate requires a careful comparison of forecasted variables against actual events to determine which elements most affect forecast accuracy.

As demonstrated on the record, the sales forecasts developed by DPS Staff use standard, recommended econometric techniques for developing models with unbiased coefficient estimates. Moreover, DPS Staff demonstrated that PSEG LI, even when it used such an approach, did so inconsistently. PSEG LI fails to refute the numerous bases underlying the DPS Staff forecast that was accepted in the DDRR recommendations or to demonstrate the soundness of its modeling technique relative to the DPS Staff's. Instead, PSEG LI on exceptions argues that we should adopt its forecast in its entirety for the 2016-2018 rate years, based upon recently provided and calibrated 2015 monthly data for C&I customers that it asserts established the veracity of its forecast. However, such reliance is both misplaced and unavailing where, as here, the forecasts advocated by PSEG LI do not represent actual sales, but instead reflect heavily-calibrated, estimated sales. There is no guarantee that any particular forecast will predict next month’s sales accurately. The goal, given the record, is to adopt the forecast that provides the most reliable bases for setting rates for the three-year rate period. On balance, these recently provided, calibrated and untested “actuals" for part of 2015, for a subset of Company sales, are not enough to outweigh the more soundly developed forecasts submitted by DPS Staff. For these reasons we accept the DDRR recommendations on the sales forecast.

Finally, PSEG LI's criticism of the observation that the RDM "will address and account for the differences between forecast and actual sales" misses the point. Obviously, we are looking for the most accurate sales forecast for the 2016-2018 rate period. We are recommending the DPS forecast because we believe it represents the best estimate of future sales for the rate plan period; however, no forecast is ever perfectly accurate. The purpose of RDMs is to eliminate the natural disincentive to support energy efficiency programs that reduce sales. Although the RDM offers a further mechanism to insulate utilities and customers against the uncertainty present in any forecast, PSEG LI’s suggestion that we are relying on the RDM to choose a deficient forecast is inaccurate. Rather, the Department’s recommendation is based upon the record evidence and the fact that we were persuaded that the DPS Staff forecast presents a more soundly constructed forecast of future sales.

Customer Growth

The DDRR also addressed the customer growth forecasts that were provided by the Company and DPS Staff (DDRR, p. 21). It noted that PSEG LI projected residential customer growth of 0.25 percent annually for 2016-2018 and C&I customer growth of 0.3 percent for 2016, 0.2 percent percent for 2017, and 0.1 percent for 2018 (Tr. 326, 377), while DPS Staff projected residential customer growth of 0.4 percent in 2016 and

0.3 percent in 2017 and 2018 and C&I customer growth of 0.4 percent, 0.2 percent and 0.1 percent in 2016, 2017, and 2018, respectively (Tr. 377-79). As stated in the DDRR, the differences in the forecasts of customer growth varied by less than 0.1 percent (DDRR, p. 21). The DDRR recommended adoption of DPS Staff's forecast of customer growth.

As noted above, the Company advocates the adoption of its forecast "in its entirety" but neither DPS Staff nor the Company specifically addresses this portion of the sales forecast on exceptions. We affirm to the DDRR's recommendation that DPS Staff's forecast of customer growth be adopted and utilized during this rate plan.

Debt Financing

There are three principal issues related to LIPA Staff's financing plans that merit discussion: use of the Public Power Model (PPM), which makes use of the Debt Service Coverage Method to determine revenue requirements; reconciliation of actual debt service costs via the proposed DSA; and the estimate of savings that will result from the planned Utility Debt Securitization Authority (UDSA) refinancing of LIPA debt.[20] As noted, the ratemaking standard imposed by the LRA requires that rates be set "at the lowest level consistent with sound fiscal and operating practices of the authority and which provide for safe and adequate service." Moreover, PAL §1020-K(6) states that LIPA must maintain rates, fees or charges sufficient to pay "the costs of operation and maintenance of the facilities owned or operated by the authority, payments in lieu of taxes, renewals, replacements and capital additions, the principal of and interest on any obligations ... as the same severally become

[20] The LRA established the UDSA to allow LIPA to finance debt through the municipal bond market with a higher credit rating and correspondingly lower cost.

due and payable."[21] Further, LIPA must establish or maintain any reserves or other funds or accounts required by the terms of its debt covenants.[22] PSL §3-b provides that the Department review any rate request of LIPA to "ensure that the authority and the service provider provide safe and adequate transmission and distribution service as rates set at the lowest level consistent with sound fiscal operating practices." Moreover, "The department's recommendation shall be designed to be consistent with ensuring that the revenue requirements related to such rate review are sufficient to satisfy the authority's obligations with respect to its bonds notes and all other contracts."

To meet this ratemaking standard, LIPA Staff and PSEG LI proposed to use the PPM to measure LIPA's annual revenue requirements. The PPM is a cash-based revenue requirement model that, according to LIPA Staff, defines the utility's revenue requirement as revenues needed to cover cash operating expenses, meet its debt payment obligations, and generate adequate coverage to 1) provide bond holders and lenders an appropriate degree of confidence that all expenses and debt/finance payments can be paid and 2) provide an appropriate contribution towards new capital additions (Tr. 184). LIPA Staff noted that the higher the degree of investor confidence, the lower its borrowing costs will be (Id.).

DPS Staff found that use of the PPM to determine the revenue requirements would satisfy two general principles (Tr. 270). First, the model should provide a reasonable estimate of the cost of service provided to customers. Second, the model should result in an accurate financial representation of how investors view LIPA in evaluating investment decisions. DPS Staff concluded the PPM should lead to financial results that

[21] PAL §1020-k(6).

[22] Id.

are consistent with the goal of providing the lowest long-run cost of service to customers (Tr. 270). No other parties have expressed opposition to use of the model (DPS IB, p. 11, Tr. 270). Accordingly, the Senior Advisory Group recommended use of the PPM for the determination of the LIPA revenue requirements in this matter.

There are three major components of LIPA's debt service requirements included in the revenue requirement model: LIPA's debt service, coverage requirements, and the cost of, and related savings from, the planned refinancing activities of the UDSA. With respect to LIPA debt, DPS Staff, LIPA Staff and PSEG LI agreed: 1) to using current interest rates to estimate debt service requirements for LIPA's future issuances (DPS IB, p. 11),[23] 2) to updating the debt service estimate with the latest available information (Tr. 293), and 3) that actual debt service costs should be reconciled to levels included in rates, with all differences collected or passed back via the DSA (Tr. 293). The Senior Advisory Group reviewed the record and all of the evidence presented and found that the uncertainties associated with LIPA's debt service costs are material enough to justify the reconciliation of debt service cost through the DSA (Tr. 209). This approach will ensure customers pay actual cost incurred for debt payments and an appropriate level of related coverage.[24]

[23] The parties agree on the estimated cost associated with new LIPA issuance and cost assumptions for variable rate debt issuances. With respect to LIPA debt, the only cost impacts in dispute related to the debt service impacts relate to recommended capital program disallowances.

[24] AARP's concerns over the DSA do not outweigh the need for LIPA to recover its actual debt costs, as LIPA is a customer owned system; it has no shareholders to make up the difference between the rate allowance and actual costs.

Regarding the debt service coverage ratios, LIPA Staff proposed to phase in increasing coverage ratios over the three rate years (Tr. 197; LIPA IB, p. 22). LIPA Staff's stated goal is to improve LIPA's credit rating one notch, to a mid-A rating, over the next five years to reduce its borrowing costs and increase access to capital markets and short-term borrowing (Tr. 192–94; LIPA IB, p. 21). The uncontroverted testimony in this matter illustrates that LIPA currently holds the lowest bond rating of the ten largest public power utilities in the United States, a rating several notches below its peer utilities (Tr. 192). DPS Staff agreed that targeted debt coverage ratios should be set at 1.20x in 2016, 1.30x in 2017 and 1.40x in 2018, excluding UDSA debt. DPS Staff indicated that, including UDSA, the targeted debt coverage ratios in the respective rate years would be 1.10x, 1.15x and 1.20x, respectively (Tr. 261; DPS IB, p. 11). LIPA Staff points out in its brief on exceptions that the agreed to coverage ratios, including UDSA debt, in the DDRR are in error, that the ratios should be 1.15x for 2016, 1.20x for 2017 and 1.25x for 2018 as its witness testified to (LIPA BOE, p. 11; Tr. 197). Aside from LIPA Staff's correction, there is no opposition to the proposed coverage targets by any other parties. We support the proposed debt service ratios, as corrected by LIPA Staff, as a reasonable approach to improving the financial position of LIPA and increasing its access to lending sources over time.

There has been an apparent open issue as to the level of savings from the planned UDSA debt refinancing that should be captured during the three years of the rate plan. LIPA Staff noted that LIPA is planning to refinance $2.5 billion of debt in several tranches and stages during 2015 through 2018 through the UDSA. Due to the UDSA higher bond rating, LIPA Staff initially estimated that the refinancing of debt would yield $155 million of savings over the three-year rate plan and about $192 million of present value (difference between principal and interest payments) over the life of the new bonds (Tr. 177-78, 243; LIPA IB, p. 23).[25] The refinanced debt instruments have an average life of 12 years, with some longer than 20 years (LIPA RB, p. 4).

DPS Staff claimed that LIPA Staff's interest rate assumptions for the UDSA debt were overstated and that current interest rates are a better indicator of actual future debt costs. DPS Staff estimated that the UDSA refinancing would yield additional savings of approximately $36.5 million ($192 million total) over the three rate years (Tr. 290). In rebuttal, LIPA Staff responded with a revised estimate of expected savings stemming from the UDSA refinancing. LIPA's current estimate of savings totals $249 million, with $172 million expected to be realized during the three rate years (Tr. 247). LIPA Staff noted that its proposed structure of the UDSA financing will produce estimated cash flow savings of $45 million in the two years beyond the rate plan (Tr. 247).

DPS Staff initially opposed the shifting of UDSA refinancing debt cost savings beyond the term of the rate plan, preferring that the savings be included in revenue requirements during the term of the plan (DPS IB, pp. 11-13). It argued that the shifting of savings outside of the rate plan would not improve LIPA's coverage ratios or other credit metrics, and would not improve its cash flow because rates will reflect the debt service requirements through the DSA (DPS IB, p. 12).

All parties anticipate significant savings to result from the UDSA refinancing of existing debt. The range of estimated savings over the three-year rate plan is $155 million

---

[25] The refinancing may involve up to 180 individual bonds and result in about 50 new UDSA bond maturities (Tr. 244).

to $192 million, with the most current estimates ranging from LIPA Staff's $172 million to DPS Staff's $192 million. The parties agreed that the full value of the resulting savings should be credited to LIPA's customers in rates or the DSA; however, did not agree initially on the appropriate value to be included in revenue requirements as estimates to which actual costs will be reconciled.

LIPA Staff stated that LIPA's goal, related to structuring the UDSA bonds, is to balance customer rate objectives with the need to meet the securitization requirements imposed by rating agencies. LIPA Staff's stated rate objectives are to provide significant savings over the rate plan while not causing a spike in revenue requirements after the plan expires (Tr. 246). The Senior Advisory Group found, as indicated in the DDRR, that these goals were reasonable and appropriate and recommended that the LIPA BOT accept the LIPA Staff's savings estimate, subject to update when the results of the first tranche of refinancing are known later this year. The Senior Advisory Group also expressed support for a full reconciliation of debt service costs to ensure that LIPA's customers bear no more or less than the actual debt costs in rates.

DPS Staff notes in its brief on exceptions that although its plan would yield more savings and lower revenue requirements during the three-year rate plan term than under the LIPA Staff proposal, it would result in higher revenue requirements in the years beyond the rate plan (primarily 2019 and 2020) (DPS BOE, p. 3). DPS Staff further states that it does not take exception to the DDRR preferred approach of spreading the additional savings over a longer time period than the three rate years, noting that the DDRR approach will help to mitigate rate increases in years 2019 and 2020 (Id.). Accordingly, the Department reaffirms the recommendation in the

DDRR, and supports the correction to the coverage ratios as discussed above.

In addition, LIPA Staff supported providing a Fall 2015 update to reconcile known terms of the 2015 tranche and adopting a 2016 second stage filing to reconcile actual savings from the 2016 refinancing to the estimates in the rate plan.[26] Any variations resulting from financings in subsequent periods LIPA proposed to be reconciled through the DSA (LIPA IB, pp. 23-24). LIPA supplied an appendix with its brief opposing exceptions, which reiterates with additional details the parties' collective agreement on those expense items that will be included in the 2015 update and in the stage filings in 2017 and 2018. We support the update and stage filings as reflected in the appendix.[27]

Operation and Maintenance Expenses

Vegetation Management Expense

Distribution Tree Trimming Program

PSEG LI proposed distribution tree trimming budgets for 2016, 2017 and 2018 of $27.4 million, $27.4 million and $17.75 million, respectively, which would equate to incremental spending over the 2015 budget by $16.2 million, $16.2 million and $6.2 million in these years (Tr. 997, 1002-03). The Company’s 2016 and 2017 budgets were calculated based on its plans to trim 2,722 miles at a projected cost per mile or “unit cost” of $9,600, plus a 4 percent adder for tree removals (Tr. 1005). The 2018 estimate is based on a unit cost of $7,889 (Tr. 1005-06). DPS Staff, on the other hand, recommended that the

[26] The 2015 savings were previously proposed for reconciliation as part of the second stage filing (LIPA IB, p. 23).

[27] Appendix II attached to this Department Rate Recommendation incorporates the principal provisions of the appendix agreed to by the parties.

Distribution tree trimming allowance be set at $17.75 million for each rate year.

The goal of PSEG LI’s vegetation management program is to minimize customer outages caused by trees and tree limbs coming into contact with overhead power lines. PSEG LI stated that in January of 2014 it initiated tree trimming of LIPA’s approximately 9,000 miles of overhead distribution system circuits on what was intended to be a four-year cycle and expanding the “trim box” around the circuits by 300 percent (Tr. 991, 1002-03).[28] The parties agreed that a four-year trim cycle represents an industry best practice and should be employed. The expanded trim box size is closer to the practices of other NYS utilities and it also is not in issue. There is a difference of opinion, however, regarding the percentage of the distribution system that should be trimmed each year of the rate plan and the resulting cost.

Under its budgets for 2014 and 2015, PSEG LI will have completed trimming about 40 percent of the distribution system by the end of 2015, the second year of its trim cycle (Tr. 1004). It proposed to complete trimming of the remaining 60 percent of the system by year end 2017, the end of the four-year cycle, and argued that funding levels of $27.4 million for 2016 and 2017 are necessary to accomplish the task (PSEG RB, p. 9). The Company indicated that the lower cost for 2018 reflects both a reduction in trimming to 25 percent of the system as well as lower costs per mile once the first four-year cycle with the expanded trim box will have been completed. It stated that, by 2018, the distribution lines would already have been aggressively trimmed, large diameter tree branches and a larger

---

[28] The extended box provides greater clearance between the trees and wires (Tr. 1111).

amount of vegetation debris would have been removed, resulting in trimming cost savings each year of the new cycle (Tr. 1006).

The DDRR acknowledged PSEG LI's concerns that the vegetation management programs are inextricably linked to system reliability, customer satisfaction and performance metrics in the OSA (PSEG IB, p. 27). It also highlighted the fact that the Company was able to adopt an average annual distribution trimming level for the first two years of 20 percent per year without a resulting negative impact to system reliability or customer satisfaction. That fact, the Senior Advisory Group found, undermined PSEG LI's claim of reliability and customer satisfaction concerns, and its alleged need to accelerate the trimming cycle to complete it in two years (Id.). The DDRR, therefore, recommended a schedule of trimming at 20 percent per year, because the Senior Advisory Staff did not see a need to accelerate distribution tree trimming so that the first program cycle is completed by the end of 2017. Instead, the DDRR recommended that the revenue requirement adopted by the LIPA BOT be based on completing the expanded trim box in 2018 (DDRR, p. 29).

The Senior Advisory Group rejected PSEG LI's claim that adopting that schedule for completing the expanded trim box would result in roughly 50,000 additional vegetation-related outages (Tr. 1005, 1090). PSEG LI's characterization of the projection as very conservative did not diminish the Senior Advisory Group's concerns that it was based on a number of unsupported assumptions and was too speculative to rely upon (DDRR, p. 29). The DDRR noted, specifically, that storm events and associated customer outages in future years cannot be predicted with any degree of accuracy. According to the Company, storm outages for 2013 and 2014 were significantly lower than in prior years, and the first part of 2015 has also been light (Tr. 1091, 1095). And, LIPA Staff pointed out that reliability on Long Island is high (LIPA IB, p. 38). The Company agreed that it has been providing excellent reliability and pointed out that it has been meeting the performance metrics in the OSA (Tr. 984). And, PSEG LI stated that it will continue to identify and prioritize circuits that need to be trimmed earlier in the cycle (Tr. 1004). Under the circumstances, the Senior Advisory Group concluded that PSEG LI had not demonstrated that the ratepayer impact of the more costly accelerated program was justified by a need to address reliability or customer service concerns (DDRR, pp. 28-29).

The Company’s $9,600 cost per mile of distribution to be trimmed in 2016 and 2017 was based on competitive bid estimates that it had received, while the reduced unit cost of approximately $7,900 for 2018 reflected savings that would be realized because PSEG LI would be starting a new trim cycle after the system was trimmed to the expanded box in 2017 (Tr. 1006; PSEG IB, p. 12). The DDRR characterized DPS Staff’s position as a proposal to use the Company's $17.75 million projected 2018 cost for all three rate years, during which PSEG LI would trim 20 percent of its distribution system per year (DDRR, pp. 29-30). The Senior Advisory Group concluded that notwithstanding DPS Staff's suggestions in testimony and briefs that PSEG LI’s cost per mile was too high, DPS Staff’s proposal actually resulted in a cost per mile approximately equivalent to PSEG's $9,600 unit cost plus 4 percent adder for tree removals. PSEG LI’s experience and recent bidding results were credited as reliable guides to the cost per mile, and since DPS Staff’s proposal closely approximates the Company’s cost estimates, the Senior Advisory Group accepted the $17.75 million level as the budget for all three years.

PSEG LI takes exception to the DDRR. In its exceptions, PSEG LI states, generally, that the DDRR miscalculates the distribution tree trimming costs, does not recommend adequate funding and is inconsistent with the provisions of the OSA (PSEG BOE, p. 15). First, the Company says that the DDRR misinterpreted DPS Staff's recommendation. According to PSEG LI, DPS Staff’s proposal was to trim 25 percent of the system per year beginning in 2016, thus commencing a new four-year cycle with this rate plan, at an average cost of $7,900 per mile (PSEG BOE, pp. 16-17 & 22). Given the DDRR’s endorsement of PSEG LI’s cost estimate of $9,600 per mile, PSEG LI asserts, the annual cost of DPS Staff’s 25 percent per year schedule would be $22.46 million, not the $17.75 million recommended in the DDRR (PSEG BOE, p. 17).[29]

The Company criticizes the DDRR’s rejection of PSEG LI's conclusion that adoption of DPS Staff's trim cycle would result in roughly 50,000 additional vegetation-related outages (PSEG BOE, p. 18). The Company argues that if the LIPA BOT were to adopt the DDRR recommendation based only on the explanation that PSEG LI has not met its burden of proof, it would be tantamount to a substitution of the Department's unexplained judgment for that of PSEG LI which, the Company says, would be contrary to the LRA and would defeat the very purpose for which PSEG LI was retained under the OSA (PSEG BOE, pp. 18-19). PSEG LI also points out that it made an offer of proof at the evidentiary hearing, in the form of its response to a DPS Staff interrogatory, to support the Company's claim that 50,000 additional outages would result if the DPS staff recommendation were to be adopted, but the record does not include that

[29] This budget estimate is based on trimming one-fourth of LIPA’s 9,000 mile distribution system at a cost of $9,600 per mile.

additional information because the ALJs rejected the offer (PSEG BOE, p. 19).

PSEG LI argues that the evidentiary record shows that reduced tree trimming will jeopardize PSEG LI's ability to meet its system reliability, financial, and storm metrics (PSEG BOE, pp. 20-21). Because, PSEG LI argues, budgets must be sufficient to provide it with a reasonable opportunity to meet the performance metrics, the DDRR recommendation is contrary to the OSA (PSEG BOE, p. 21).

In its brief opposing exceptions, DPS Staff says that the Company mischaracterized the position previously taken by DPS Staff, which DPS Staff goes on to restate. DPS Staff suggests that the DDRR recommendation is consistent with DPS Staff's approach (DPS RBOE, pp. 15-17). It further argues that PSEG LI's reliance on asserted evidence of an increase of 50,000 outages does not shift the burden to DPS Staff to prove that its recommendations would not adversely affect PSEG LI's OSA metrics performance (DPS RBOE, p. 16).

Also responding to PSEG LI's exceptions, LIPA Staff notes that PSEG LI and DPS Staff clearly differ on what DPS Staff recommended and what the record supports as an annual budget level (LIPA RBOE, p. 6). LIPA Staff asserts that the precise numbers are hard to unravel and that neither the evidence in the record nor the offer of proof provides the clarity or complete explanation needed (LIPA RBOE, pp. 6, 8). Considering the importance of system reliability, the difficulties encountered by the parties in sorting out the tree trimming issue in the record, and PSEG LI's new status as the service provider, LIPA Staff supports setting the annual budget at approximately $22 million for each rate year -- approximately halfway between what it asserts are the DPS Staff and PSEG LI estimates. Moreover, LIPA Staff proposes to reconcile actual expenditures to the annual budget, with any variances being refunded or recovered in the second and third-stage filings (LIPA RBOE, pp. 6-8). It predicts that the experience gained from second and third stage reconciliation of these expenses will make it easier to forecast these costs in the future and obviate the need for a special reconciliation of the expense (Id.).

We recommend denial of PSEG LI's exceptions and LIPA Staff's proposal in response, and instead support the Senior Advisory Group's original recommendation. Whether or not the recommendation was or is an adoption of the DPS Staff position, it is important to clarify that the Department's recommendation is for PSEG LI to complete the expanded trim box cycle over the three years of the rate plan, trimming an average of 20 percent of the system per year as it has done in 2014 and 2015. Thereafter, in 2019, with one expanded trim box cycle complete, PSEG LI will be well situated to commence trimming on a four-year cycle, at a reduced cost per mile. We recommend that the budget for each of the three years be set at $17.5 million, which, as stated earlier, roughly comports with PSEG LI's estimated cost per mile of $9,600, plus a 4 percent adder for tree removals.

We are not persuaded by the parties' arguments in the exceptions process to deviate from the DDRR recommendation.[30] PSEG LI's claim that the DDRR analysis fails to satisfy the legal burden of an agency to provide an adequate statement of the factual basis for the determination is erroneous. PSEG LI's contention is based solely on the failure to credit its witness's testimony that there would be 50,000 additional

[30] Much of the briefing seems to have been directed at the parties' litigation positions before us rather than at the DDRR recommendation itself, and those arguments therefore need not be addressed here.

outages if the schedule for completing the expanded trim box cycle were expanded through 2018.[31] PSEG LI ignores the other evidence that was considered as part of the Senior Advisory Group analysis -- the extreme uncertainty of predicting storm events; PSEG LI's testimony of significantly lower storm outages in 2013, 2014 and the first part of 2015; the uncontroverted evidence that Long Island electric reliability is high and that PSEG LI has been meeting OSA performance metrics; and PSEG LI's testimony that it will continue identifying and prioritizing circuits that need to be trimmed earlier in the cycle. The factors all contributed to the conclusion, as explained in the DDRR, that there is no need to accelerate the distribution system tree trimming to complete trimming to the larger box size by the end of 2017. In addition, PSEG LI is expected to undertake storm hardening actions over a four-year period under the FEMA funding agreement (Tr. 57). These actions will presumably assist the company in meeting reliability performance metrics.

Complicating the tree trimming expense forecast for Long Island is the massive investment in storm hardening taking place over the next several years, which includes tree trimming expenditures in the storm hardening capital budget (i.e., funds for tree trimming in addition to those outlined in PSEG LI's

[31] PSEG LI's claim that it was denied the opportunity to submit further evidence supporting the 50,000 outage estimate is not borne out by the record. The ALJs denied, as an improper attempt to bolster direct testimony, which must be prefiled, a request by PSEG LI to admit its own response to a DPS Staff interrogatory. The record, however, also clearly demonstrated that the ALJs acknowledged that PSEG LI would be able to present this information through the Company's witnesses who were scheduled to testify (TR. 937-44). The fact that the Company failed to avail itself of the opportunity to flesh out the record on this issue through its witnesses is not a legitimate basis for criticizing the DDRR conclusion.

operating budget). The project includes trimming the approximately 300 mainline circuits to be hardened before commencing construction on each circuit. We note that this project may well affect the prudent pace of tree trimming, hence leading to less expense as part of the operating budget than forecast by PSEG LI. The abundant budget for storm hardening illustrates the difficulty in attempting to isolate and evaluate a reasonable opportunity to earn performance metric incentives on a line-by-line basis as argued by PSEG LI. We are persuaded by the assertions, made by LIPA Staff, that the storm hardening investment will provide significant day-today reliability benefits that may complement (or even exceed) the benefits provided by PSEG LI’s proposed tree trimming program.

Despite an apparent misunderstanding by the parties of the DDRR, leading to some confusion in the exceptions briefs, we think the record is much clearer than LIPA Staff indicated, and therefore the reconciliation process proposed by LIPA Staff is not necessary. PSEG LI clearly accepts the DDRR estimated cost per mile (PSEG BOE, p. 22 & n.16), which is based on the Company’s litigated position, so, with clarification regarding the miles to be trimmed during each year of the rate plan, PSEG LI has no cause for concern that it might fail to meet the distribution tree trimming budget. The Department sees no need to expand the scope of costs to be updated to include this item.

Transmission Tree Trimming Program

As noted in the DDRR, the annual funding level for transmission tree trimming is not in dispute. Opposition exists over the DPS Staff recommendations that PSEG LI implement and comply with 16 NYCRR Part 84 and the best practices adopted by the Commission for other NYS utilities and identify and report to the Department for review, by the end of 2017, all overhead 69 kV and 138 kV transmission rights-of-way (ROWs) (Tr. 1118;

DPS IB, p. 16).[32] PSEG LI argued that documenting and reporting the ROWs is unnecessary and too costly (PSEG IB, pp. 39-40; PSEG RB, p. 14).

The DDRR included a recommendation that PSEG LI follow Commission best practices regarding transmission ROW maintenance practices, which were developed through experience with a variety of utilities. The Senior Advisory Group found no reason why the best practices should not be applicable and be used as a guide to PSEG LI.[33]

The DDRR also incorporated a Senior Advisory Group recommendation that PSEG LI provide a report to the Department by the end of 2017 on transmission ROWs, and include in the report an explanation of how it will comply with Commission best practices going forward. The DDRR noted that the Company should be able to coordinate with DPS Staff on the submission of documents needed that identify LIPA's ROWs. The Senior Advisory Group found PSEG LI's unsupported claim, that providing the documents would be too costly, to be unpersuasive. The Company indicated that it has maps identifying the transmission circuits and has records indicating the associated deeds and easements (Tr. 1062).

The DDRR noted that there is no evidence in the record regarding any meetings between these parties to identify records that might be available to satisfy the DPS Staff request, or in

[32] Case 10-E-0155, Commission Proceeding on Electric Utility Transmission Right-of-Way Management Practices, Order Adopting Recommendations (Issued May 27, 2011) and Case 04-E-0822, Investigation into Electric Transmission Right-of-Way Management Practices, Order Requiring Enhanced Transmission Right-of-Way Management Practices by Electric Utilities (issued June 20, 2005).

[33] DPS Staff testified that PSEG LI's performance in this area has been well below that of the other utilities in New York, which supported its request for PSEG LI to follow statewide best practices (Tr. 1116-17).

the alternative other records or documents needed and the costs to obtain them. Thus, the extent to which available information would satisfy the DPS Staff request or would need to be supplemented is unknown. The Senior Advisory Group recommended that the Company be required to confer with LIPA Staff and DPS Staff regarding the available documents that would satisfy the DPS Staff request and how best to obtain, in the least costly way, other needed documents that are not in the possession of PSEG LI or LIPA. It noted that until these steps are taken and the work involved in collecting and transmitting the information is known, there is no reason to modify the end of 2017 date proposed by DPS Staff for receipt of the information.

Although not an issue for determination, the DDRR discussed the fact that the Company does not agree with DPS Staff on the appropriate trim cycle, with PSEG LI claiming that a four-year cycle is appropriate, and DPS Staff arguing that a longer trim cycle is appropriate because clearance widths for these transmission lines should be much greater than for distribution lines (Tr. 1117). DPS Staff, however, did not recommend a specific trim cycle for the transmission system. DPS Staff argued that adopting the best practices should increase annual tree removals to the maximum ROW width (Tr. 1118). As pointed out in the DDRR, the proper number of years in a cycle and ROW width for transmission line tree trimming is not specified in the Commission orders adopting utility best practices. Instead, the Commission stated:

> As a general rule, ROW should be sufficiently wide not merely to trim, but to remove completely to the ground-level, any undesirable vegetation that in any way encroaches into a utility-established priority zone. In practical application of the rule by its terms, the utilities must consider particular conductor heights and the relative location and characteristics of undesirable vegetation. This

> recommendation will allow utilities to calculate optimal ROW widths based on actual conditions, rather than on somewhat arbitrary voltage designations, and to compare existing ROW widths to the optimal widths to identify deficient ROW.[34]

The DDRR reflects an expectation that PSEG-LI would utilize a similar practice already and explained that if PSEG-LI does not maximize the extent to which it is able to trim the transmission ROWs, it runs the risk and associated consequences of vegetation interference and failing to meet applicable performance metrics.

The DDRR concluded that providing a report to the Department on the 69kV and 138kV overhead transmission ROWs would assist the Department, PSEG LI and LIPA in gaining a complete understanding of the transmission system, the extent to which the system is being maintained consistent with the Commission's standards and what, if any, exceptions from those standards may be warranted due to unique characteristics of LIPA's transmission system. That information should also assist the parties in reaching a resolution of the appropriate trim cycle for the system.

In addition to reiterating testimony it presented for the record, PSEG LI makes several arguments in support of its exceptions to the DDRR. The exceptions are premised either on its claim that the evidence supports a contrary conclusion or that there is no legal or contractual basis supporting the action that the DDRR recommends (PSEG BOE, p. 23). PSEG LI contends, first, that the DDRR's conclusion that it performed well below that of other utilities with respect to vegetation-related trips from tree contacts has been disproved (Id.). The Company contends that it demonstrated its electric system performance is as good, or better, than other in-state electric

[34] Case 04-E-0822, supra, June 2005 Order, p. 24.

utilities and that the DPS Staff claim PSEG LI experienced more tree contacts than other electric utilities in the state is inaccurate (PSEG BOE, pp. 23-24; Tr. 1010). The Company's second argument that the DDRR recommendation is erroneous is predicated on the Company's position that it implemented clearing protocols consistent with good industry practice and consistent with those of other utilities in the region and must contend primarily with a transmission system constructed on municipal roads with trees growing directly under the lines. And, aside from needing to get permission to remove the trees from the municipalities and customers owing them, it says, the cost of removal would be prohibitive and would result in negative customer responses (PSEG BOE, p. 24).

The Company’s argues the DDRR unnecessarily adopted DPS Staff's recommendation that ROW rights be documented and reported to the Department because a process is in place by which the rights can be easily determined without engaging in the time consuming process outlined in the DDRR (Id.). In support, it reiterates the testimony of a Company witness who stated that PSEG LI maintains surveys going back years and pulls out the records when needed to perform a project or when a determination of ROW rights to a particular parcel is warranted to facilitate tree trimming or removal process (PSEG BOE, p. 25). It asserts that the DDRR provision would impose additional costs for no demonstrated benefit and should have been rejected (Id.).

PSEG LI's fourth argument in opposition to the DDRR is that there is no legal or contractual basis for requiring the Company to follow the Commission regulations and orders related to ROW management (Id.). It points out that PSL §3-b(2)(b) expressly exempts the Company from being an electric corporation and, thus, the Department has no authority to impose requirements (Id.). Moreover, PSEG LI says that LIPA's authority to impose the requirements must come from the OSA and the DDRR did not identify any basis in the OSA that would allow LIPA to impose the requirements (PSEG LI, BOE, pp. 25-26).[35]

LIPA Staff highlights the Company's concerns over the cost and need to document ROW rights in its brief on exceptions. Addressing the DDRR recommendation that PSEG LI, DPS Staff, and Authority Staff work together to identify the available documentation, and "how best to obtain in the least costly way other needed documents . . .," LIPA Staff comments that it looks forward to working with the other parties to implement that sound recommendation (LIPA BOE, p. 9).

According to DPS Staff, a key to PSEG LI preparing a long-term strategy for and facilitating the removal of more vegetation on the transmission ROWs is having an understanding of what legal rights it has to effect the removal of the vegetation (DPS RBOE, p. 18). DPS Staff states that it agrees with the DDRR recommendation to consult with PSEG LI and LIPA Staff in an effort to reach agreement on efficient and cost effective solutions regarding the ROW documentation issue (Id.). DPS Staff expresses confidence that the parties will be able to reach an agreement on the process.

With respect to PSEG LI's claim that no basis exists to enforce the Commission's best practices because it is not required by the OSA, DPS Staff states, without amplification, that the OSA embraces prudent utility practices which may

[35] LIPA Staff notes, in contrast, that pursuant to OSA §§ 4.2(A)(2)(e) and 6.2(E), PSEG LI is responsible for rate case preparation, participation and prosecution before the DPS and for providing evidentiary and other support for all information contained in the three year rate plan (LIP RBOE, p. 2).

include practices adopted by other utilities (DPS RBOE, pp. 18-19).

DPS Staff contends that the PSEG LI claim, of the tree-related outage data showing the LIPA transmission system to be performing as well as or better than upstate electric utilities, is inaccurate (DPS RBOE, p. 17). According to DPS Staff, PSEG LI based its position on only one year of data that removed major storm events, whereas the upstate utility data that the Company was comparing PSEG LI to incorporates the major storm statistics (DPS RBOE, pp. 17-18). It points out that the upstate utility data also covers multiple years. DPS Staff also reiterates the testimony of its witness, who stated that a comparison of the PSEG LI data on a total annual outage basis to the upstate utilities shows PSEG LI to be underperforming in transmission vegetation outages (DPS RBOE, pp. 17-18; Tr. 1058-59).

DPS Staff observes, with respect to PSEG LI's claim that trimming of the transmission system on a four-year cycle is good industry practice, that no upstate utility trims their transmission ROWs on a four-year cycle (Id.). It points out that the upstate utilities have, nevertheless, made progress in minimizing costs and improving reliability by implementing the Commission's best practices, practices which result in the removal of more trees under and along the transmission ROW (DPS RBOE, p. 18). Although it acknowledges that there are nuances associated with managing vegetation of Long Island, DPS Staff indicates that it does not agree with using a four-year trim cycle on a long-term basis.[36]

[36] DPS Staff indicated that longer trim cycles are appropriate for 69kV and 138kV because clearance widths should be much greater than on distribution circuits which would lead to longer trim cycles (Tr. 1116).

We do not find the arguments raised by PSEG LI on exception to the DDRR to warrant a change in the DDRR transmission tree trimming program recommendations. The Company has not raised any exceptions regarding the substance of the record that were not considered by the Senior Advisory Group in arriving at the DDRR. Although the DDRR may not provide an exhaustive discussion of the evidence presented concerning the transmission tree trimming program and the positions stated by the parties in post-hearing briefs, the information was considered.

We also disagree with the Company's contention that there is no legal or contractual basis for requiring it to follow the regulations adopted by the Commission and the Commission orders issued with respect to ROW management. OSA §4.2(A) expressly states that PSEG LI, as the service provider, "shall provide Operations Services for the T&D System on behalf of LIPA at all times in accordance with the Contract Standards." And, Contract Standards is defined in the OSA to mean, in part, "the substantive requirements and standards and guidelines established by the [Public Service Commission] from time to time that apply generally to the operation and maintenance of electric transmission and distribution systems in the State of New York, except to the extent LIPA directs the Service Provider not to follow any such requirement, standard or guideline and Prudent Utility Practice." (OSA, Appendix 1, p. 5). There was no evidence presented to suggest that the LIPA BOT directed PSEG LI not to follow NYS best practice the Commission's standards or guidelines.

We, therefore, recommend that the LIPA BOT adopt the recommendations as described above and in the DDRR.

Pole Inspection Expense[37]

As explained in the DDRR, PSEG LI performs distribution pole inspections on a 10-year cycle, employing both visual inspections and physical integrity tests (Tr. 1012, 1076). PSEG LI has a goal of inspecting 340,000 distribution poles (Tr. 1076) during the current 10-year cycle that commenced with year 2013 and will conclude with year 2022 (Tr. 1072, line 3; 1073, line 15; 1074, lines 11-24).[38]

PSEG LI expects to have inspected 15,511 distribution poles during the period 2013-2015 (Tr. 1125). In order to maintain its overall goal of inspecting a total of 340,000 distribution poles during the current 10-cycle, PSEG LI proposed an accelerated inspection schedule of 68,000 poles each year of the rate plan, with inspection and treatment costs of $1,869,847 and $1,325,271, respectively, or $3.2 million in total each rate year (Tr. 1018-20).[39]

The DDRR noted that DPS Staff agreed with maintaining the current 10-year cycle, but DPS Staff disagreed with the overall number of poles remaining to be inspected by 2022, PSEG LI's proposed total budget, the number of poles targeted for inspection each rate year, and the cost and extent of the

---

[37] There are no disputed issues concerning transmission pole inspections.

[38] PSEG LI uses 325,000 poles as its starting point and assumes that 1,500 poles per year will require re-inspection to arrive at its 10-year total of 340,000 poles (325,000 + (1,500 x 10 years)) (see, e.g., Tr. 1076). As noted later, the correct number of LIPA-owned distribution poles is 324,771 (Tr. 1023, 1125).

[39] In the four years after the rate plan (2019-2022), PSEG LI proposes to inspect roughly 32,000 distribution poles per year (Tr. 1074). Mathematically, PSEG LI's proposal would provide for an additional 332,000 pole inspections by 2022 and a total of 347,511 pole inspections over the 10-year cycle. This total is 7,511 over PSEG LI's stated target of 340,000.

planned distribution pole inspections and treatments. DPS Staff estimated that 325,499 distribution poles would need to be inspected during 2016-2022 (DPS IB, p. 18).[40] Unlike PSEG LI, DPS Staff would allocate the remaining number of inspections evenly over the remaining 7 years, resulting in annual inspection of 46,500 poles per year. DPS Staff also proposed an annual budget of $1.09 million per rate year, which is based on providing funding of $395,248 (roughly $8.50 per pole) for pole inspections and $697,404 (which averages to $15 per pole) for pole treatments (Tr. 1125-30). DPS Staff also proposed that PSEG LI be required to separate the costs of inspection and treatment for tracking and reporting purposes (DPS IB, p. 19; DPS RB, p. 13).

As further reported in the DDRR, PSEG LI explained that it is attempting to craft a remedial program. It argued that, by accelerating its pole inspection and treatment program during the rate plan, its proposal would improve reliability and keep the pace of inspections to remain on target for achieving a 10-year inspection cycle. It also argued that by providing for more comprehensive inspections -- inspections that will include visual, sound only, sound and bore, and excavation, sound and bore inspections -- its proposal also would be more effective at avoiding prematurely incurring the $6,500 cost of replacing a distribution pole that, with timely inspection and adequate treatment, could have enjoyed an extended service life (PSEG IB, pp. 41-49). PSEG LI's witness testified that the average age of a LIPA-owned distribution pole is 38 years, adding that roughly 37.5 percent of distribution poles greater than 20 years will require excavation, sound and bore inspections, and treatment to

[40] DPS Staff uses 324,771 poles as its starting point, adds a 5 percent re-inspection allowance (16,239) and subtracts the number of poles that should have been inspected by the end of 2015 (15,511) to determine its remainder (DPS IB, p. 18).

retard future deterioration of the poles, and that, with such treatment, the service life of the pole could be extended by 10-15 years (Tr. 1022).

The DDRR found more persuasive PSEG LI's justifications for its proposal to provide for a more comprehensive inspection protocol than that proposed by DPS Staff. It noted that DPS Staff's proposal was premised, in part, on its belief that, since most of the LIPA-owned poles are less than 20 years old, visual and sound inspections should be sufficient in many instances. However, it noted that visual and sound inspections cannot detect subsurface deterioration or loss of strength due to internal decay, while excavation and boring inspections can effectively detect such issues (Tr. 1015-16, 1153-55). Thus, in the DDRR, it was determined that these factors seemed to warrant providing funding at the levels proposed by PSEG LI.

The Senior Advisory Group shared DPS Staff's concern that the proposed rate of acceleration in the volume of distribution pole inspections may prove overly aggressive and transfer too many of the associated costs into too compressed a period of time, thus unduly burdening rates during the rate plan. And, as noted in the DDRR, the Senior Advisory Group also determined that PSEG LI had not demonstrated that the acceleration it proposed would prove more successful in achieving the reliability benefits that it touts than would DPS Staff's proposed approach to maintaining the existing 10-year cycle. Accordingly, the Senior Advisory Group recommended adopting DPS Staff's proposal to inspect 1/7 of the remaining number of poles to be inspected and re-inspected in each of the rate years. It reasoned that providing for a levelized rate of inspections/re-inspections, when combined with the adoption of the funding levels proposed by PSEG LI, should ensure the implementation of effective inspection and treatment protocols, provide for reasonable progress toward the timely completion of the distribution pole inspection program, and realize certain reliability and cost benefit, while avoiding undue upward pressure on rates.

The Senior Advisory Group however disagreed with PSEG LI's and DPS Staff's calculation of the number of remaining poles to be inspected, and instead determined that, in order for the Company to stay on its current 10-year cycle and achieve its overall target, a total of 319,760 poles would need to be inspected during the period 2016-2022. Using the levelized approach, combined with the estimate of remaining pole inspections, the Senior Advisory Group found that the Company would need to inspect 45,680 poles per year from 2016-2022 and therefore recommended a distribution pole inspection/treatment budget of approximately $2.15 million per rate year. It reasoned that, since the target goal of inspecting 45,680 poles per rate year is roughly 67 percent of the number of poles proposed by PSEG LI, the amount recommended in the DDRR, which represents 67 percent of the rate year amount proposed by PSEG LI, should be sufficient to provide for the inspection and treatment of 45,680 poles per rate year (DDRR, pp. 33-37).

Both PSEG LI and DPS Staff take exception. PSEG LI asserts that there are several reasons why it should be permitted to complete the inspection of all the poles in a shorter, more aggressive period, before resuming a normal, ten-year inspection cycle. First, it states that there was a significant period when the inspection program was halted entirely by National Grid in 2006, and not re-started until 2012 and that, as explained by its witness, due to this hiatus, "[i]t had been six years of no inspections" and "some of these poles were going to be waiting sixteen, seventeen years before they got inspected" thus warranting "some level of acceleration" (PSEG BOE, pp. 28-29, citing Tr. 1021, 1074, 1150).

Second, PSEG LI claims that, while it would have liked to have begun the more comprehensive inspection program sooner, budgetary constraints imposed as a result of the 2013-2015 rate freeze required that the full program be delayed. Thus, says PSEG LI, performing an annual inspection of 68,000 poles will allow PSEG LI 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 BOE, pp. 28-29, citing Tr. 1013).

Third, PSEG LI contends that "[c]ontrary to the DDRR's observation that 'PSEG LI has not demonstrated that the acceleration it proposes will prove more successful in achieving the reliability benefits that it touts than would DPS Staff's proposed approach,'" reliability would, in fact, be adversely affected with the diminished inspection program (PSEG BOE, p. 29, citing DDRR, p. 35). It cites testimony that "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. ... [providing] greater reliability benefits by identifying deteriorating poles before they become a problem - either by failing and causing outages or by needing replacement" and that DPS Staff's recommendations "would provide near term savings at a longer term greater cost" (PSEG BOE, p. 29, citing Tr. 1022).

PSEG LI concludes that its program should have been adopted as proposed. It also highlights a statement from LIPA's initial brief that,"[b]ased on the information provided by PSEG LI in rebuttal concerning the reliability and maintenance benefits, and the six years without such a program, it is possible that under PSEG LI's rebuttal proposal the benefits outweigh the modest additional cost” adding that "LIPA is correct" (PSEG BOE at 30, citing LIPA IB, p. 39).

DPS Staff argues that the DDRR was correct to levelize the remaining number of pole inspections but asserts that the DDRR erred because by providing PSEG LI with $2.15 million each rate year, it utilized PSEG LI's "inaccurate" and "overstated" unit cost of $47 per pole (DPS BOE, p. 4). DPS Staff agrees that excavation and boring inspection can effectively detect subsurface deterioration which visual and sound inspections may not detect, but it urges that the DDRR recommendation be modified to reduce funding to "a more appropriate and reasonable level" (Id.)

DPS Staff notes that the $47 per pole unit cost was based on the 2014 sample data provided by PSEG LI, data DPS Staff says was a "small sample size of only 2,095 poles," representing less than 1% of the total distribution poles. DPS Staff also contends that PSEG LI agreed that such a small-sized sample is not a statistically valid number (DPS BOE, p. 4, citing Tr. 1069-1070).

Of the 2,095 poles treated as part of the 2014 program, DPS Staff states that approximately 80% of the poles received internal treatment; 50% were excavated and received external treatments; and about 88% of the pole inspections were performed with boring inspections (DPS BOE, p. 4, citing Exh. 84, p. 218). DPS Staff claims, therefore, that if the DDRR's recommended unit cost is adopted, it would mean that in each rate year, 88% of poles require bore inspection and 80% of the poles need internal treatment, even though PSEG LI, itself, stated that only 37.5 percent of the LIPA-owned poles over 20 years old would require excavation, bore inspection, and potentially treatment (DPS BOE, p. 4, citing Tr. 1022). In other words, says DPS Staff, the percentages resulting from the limited 2014 data are admittedly inaccurate and overstated, resulting in an inflated $47 unit cost, and the small data sample collected from 2014 should not be the basis to formulate the estimated unit cost of the inspections and treatments of the pole inspection program in future years (DPS BOE, pp. 4-5, citing Tr. 1070).

DPS Staff adds that PSEG LI provided no evidence demonstrating that the level of these activities based on the 2014 sample needed to be continued consistently in 2016 through 2018. Therefore, DPS Staff recommends as "a reasonable compromise to recognize more realistic levels of work for inspection and treatment going forward," a funding level of $1.62 million. DPS Staff notes that the derivation of this level results from "an equally divided or midpoint level of funding between [DPS] Staff's original recommendation and the level of funding provided in the [DDRR]" (DPS BOE, p. 5), but it asserts that $1.62 million "is expected to set costs at a level that is consistent with activities to be taken over the next three years as adjusted in [DPS Staff's] recommendation(s) and recognized by PSEG LI (Tr. 1022)" (Id.).

Both parties addressed this issue in their briefs opposing exceptions. PSEG LI contends that DPS Staff's earlier estimate of pole inspection costs was properly rejected because it was based on an inspection method that was unlikely to determine subsurface deterioration in a pole's condition and strength (PSEG RBOE, p. 1, citing DDRR, p. 35). PSEG LI notes that DPS Staff is now proposing a "compromise" mid-point funding amount of $1.62 million, but it says that DPS Staff's new approach would not provide sufficient funding and would undermine system reliability and impose greater long-run costs than the more robust inspection and treatment program it originally proposed.

After reiterating several points asserted in its brief on exceptions (and already summarized above), PSEG LI also addresses DPS Staff's contention that PSEG LI's "unit costs" for this activity are too high because they are based on 2014 pole inspection and treatment experience. PSEG LI responds that its accelerated inspection program is designed to target the most "at risk" poles and inspect and treat them to either prolong their average service lives or remove them as hazards to safety and reliability. PSEG LI states that the allegedly "high volume of activity identified in the limited sample size used to determine PSEG LI's original costs" that DPS Staff complains about is "high precisely because PSEG LI was targeting the very same high risk, aging poles in 2014 that its accelerated inspection program will target in 2016-2018." Because the population of poles targeted will be the same during the rate year as during 2014, says PSEG LI, the cost experience will be the same, thereby rendering irrelevant the fact that only 37.5% of the system poles are older than 20 years.

PSEG LI notes that the current inspection program addresses circuit locations with a high percentage of poles greater than 20-years old. Moreover, PSEG LI notes that its costs were not based on a "unit cost" but rather on the detail shown in testimony, especially Table 5 of its rebuttal testimony, which reflects its current program of inspecting and treating the targeted population of poles greater than 20 years old. Under such a targeted program, the Company indicated 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 and re-inspection cycle is performed in two to three years.

PSEG LI also argues that DPS Staff's compromise funding level ignores the metrics that PSEG LI is required to achieve (e.g., SAIFI, the system average interruption frequency index). PSEG LI adds that DPS Staff's compromise funding level has no record basis (PSEG RBOE, pp. 1-5).

DPS Staff responds that PSEG LI's claims regarding the DDRR's recommended annual levelization of pole inspections ignore the fact that the DDRR agreed with PSEG LI and DPS Staff that the pole inspection program should be complete by 2022. Therefore, PSEG LI's characterization of the recommended program as less "comprehensive", says DPS Staff is incorrect.

DPS Staff also counters that PSEG LI has not provided any additional record support for its "ramp up" proposal and has taken a "questionable" approach by asserting that the difference between what is recommended and what it proposed, at "only $1 million annually" is a "minimal" amount that should be approved. DPS Staff argues that such a premise does not provide a sufficient basis for supporting PSEG LI's proposal or altering the decision to recommend a levelized inspection and treatment approach (DPS RBOE, pp. 13-15).

The DDRR recommended the same 10-year pole inspection cycle advocated by the Company and DPS Staff because it recognized that a 10-year pole inspection cycle is good utility practice. The DDRR calculated a different number of poles remaining to be inspected than advocated by either DPS Staff or the Company and neither party appears to challenge that calculation. To that calculation of the number of poles remaining to be inspected during the balance of this 10-year cycle, DPS Staff's levelized approach was applied, using the Company's estimated costs to derive a recommended annual rate year funding level of $2.15 million for pole inspections and treatment. By providing funding at the same levels, on a percentage basis, as were originally proposed by the Company, the DDRR provided a level of funding that is as "comprehensive" and that allows for the same "targeted" approach as that outlined by the Company; we therefore affirm that recommendation.

We acknowledge that the program as recommended is not as accelerated as PSEG LI originally proposed. The recommendation, however, accommodates a reasonable amount of acceleration and keeps PSEG LI on its current 10-year inspection cycle. Even on exceptions, PSEG LI still has not persuasively established that inspection of 68,000 poles per rate year -- a rate of acceleration double what PSEG LI plans for the out years (2019-2022) and double what it would have been doing had there been no inspection "hiatus"[41] -- is more appropriate or reasonable than the accelerated rate that we recommend. Other than its vague and unspecified assertion that "reliability and other benefits" would be realized, PSEG LI did not, and still has not, persuasively demonstrated that the difference between the additional inspections provided for under its original proposal and those provided for under the modified, but still-accelerated DDRR approach, justify the imposition of an additional $1.05 million rate increase per rate year. Also, the mere existence of a metric, such as SAIFI, does not justify approving a more accelerated rate of inspections or a higher funding amount than we are recommending.

We similarly recommend the denial of DPS Staff's exception. Other than its original and lower funding proposal, which was rejected for reasons not addressed by DPS Staff on exceptions, DPS Staff provides no basis for an additional reduction in funding of $.53 million per year.

[41] See Tr. 1072.

The DDRR also recommended that PSEG LI be required to separately track such pole inspection and treatment costs (DDRR, p. 36). PSEG LI excepts. PSEG LI argues that the "concerns" stated by DPS Staff do not support the recommendation that PSEG LI separately track pole inspection and treatment costs. PSEG LI says there is no dispute that (1) the crews that inspect poles also apply treatment at the same time to poles requiring it and (2) it would be inefficient to have one crew inspect poles and another return to treat them. It asserts that these are the reasons why the costs are not, and should not be, separated. PSEG LI adds that since the breakdown of the costs between inspection and treatment does not change the need for the pole inspection program expenses, nor does it reflect the realities of how the program operates, separating the costs is entirely unnecessary.

As evidenced by the discussion above, there was significant and vigorous testimony and argument about the appropriate cost and extent of pole inspections and treatments. PSEG LI has shown that it is capable of separating such costs (see, e.g., Tr. 1017-1018 and Exh. 84). And, while PSEG LI contends that it is "unnecessary," it seems that the value of tracking and providing such costs would be readily apparent when one considers the time and resources that have been expended contesting this issue. The ability of PSEG LI to readily provide such information on a more representative sample size may avoid or diminish such debates about these costs in the future and may provide a better, more persuasive, and stronger basis upon which to measure the success of the program with respect to achieving the benefits PSEG LI attributes to it. Therefore, we recommend denying PSEG LI's exception and adopting the DDRR’s recommendation that PSEG LI separately track pole inspection and treatment costs.

BES Staff Funding

PSEG LI proposed a funding level of $900,000 for each of the three rate plan years to cover additional costs that it anticipates will be incurred to meet compliance obligations pursuant to the modified definition of the Bulk Electric System (BES), which were approved in December of 2012 by the Federal Energy Regulatory Commission (FERC).[42] DPS Staff recommended an annual funding level of $450,000.

In addition to two 345 kV circuits covered under the prior BES definition, there are 119 existing LIPA assets that will be classified as BES under the new definition and become subject to new reliability requirements and compliance enforcement beginning in July of 2016 (Tr. 1429; PSEG IB, p. 51). PSEG LI stated that, under the new BES definition, LIPA, as a transmission operator, load serving entity, transmission operator, and distribution provider, will be subject to 79 reliability standards and 531 operational requirements, whereas prior to the change it was subject to 49 reliability standards and 354 requirements (PSEG IB, pp. 51-52). And PSEG LI, as the service provider, will be responsible for performing the compliance work on LIPA's behalf.

To support its funding request, PSEG LI provided a categorized breakdown, by applicable standard, of additional responsibilities for complying with the new NERC standards and provided an estimate of the total number of annual labor hours needed to accomplish each function (Tr. 1027-30, Exh. 68). It asserted that seven employees will be needed at a cost of $1.55

[42] FERC approved a North American Electric Reliability Corporation (NERC) proposed expanded BES definition which creates a general presumption that facilities operated at or above 100 kV are part of the BES. The definition denotes other facility configurations that are also included and configurations that are excluded (FERC Order 773).

million (Exh. 71, pp. 260-63; Tr. 1026).[43] However, PSEG LI noted that the $900,000 requested will only be used to fund four of these positions; the other three positions will be funded through $600,000 of operational savings from management, administrative, supervisory and technical (MAST) personnel (Tr. 1030; PSEG LI IB, p. 54).

DPS Staff commented that PSEG LI initially categorized the additional work as non-labor, later correcting it to show the costs as all labor. DPS Staff pointed out, in addition, that the Company provided workpapers that indicated a labor increase of 10 positions at a cost of $2.16 million was needed to satisfy the BES requirements and, with projected internal savings of $1.3 million, the Company asserted a need for about $900,000 to cover the new hires (DPS Staff IB, p. 20). But, when PSEG LI revised its incremental labor calculations to $1.55 million, it reduced the internal savings from $1.3 million to $600,000, while still maintaining its $900,000 funding request for new hires (DPS Staff IB, p. 20). DPS Staff argued that, in view of the limited information PSEG LI provided for review and inconsistencies between the Company’s discovery responses and its rebuttal testimony, the incremental labor allowance for BES staffing should be cut in half to $450,000. PSEG LI argued in response that DPS Staff’s recommendation was arbitrary and unsupported because DPS Staff provided no workpapers or backup documentation to support the $450,000 amount (PSEG RB, p. 19).

The DDRR noted the additional work presented by the change to the BES definition and increased system assets covered by the new requirement will be significant. However, setting of an appropriate allowance for new staffing is complicated by the

[43] The $1.55 million is equivalent to 7.2 full time equivalent (FTE) employees at an average salary of $115,000 plus $100,740 in benefits, pensions and other post-employee benefits (PSEG IB, pp. 53-54).

fact that the record contains no PSEG LI workpapers or other documentation or testimony showing how the estimates of annual labor hours were developed for each of the activity functions identified. For example, the DDRR pointed out that the Company indicated, under the category of Transmission Operations, Training Development/Maintenance and Training Delivery will consume over 1,600 hours annually (Exh. 68). The Senior Advisory Group observed that it seems unreasonable the same amount of training will be required for each year of the rate plan, absent disclosure of what specifically is envisioned for the BES activities, and there is no way to ascertain whether the annual man-hour projections for the various tasks are reasonable. The DDRR reported that PSEG LI had the burden of demonstrating the reasonableness of its recommendation and that PSEG LI did not meet its burden. The Senior Advisory Group recommended, as an alternative, that the LIPA BOT adopt a $450,000 annual funding level for the term of the rate plan, based on the amount DPS Staff supported, because there were no other funding recommendations made and funding at least to this level was uncontested.

In its brief on exceptions, PSEG LI reiterates extensively its testimony regarding the federal change in the BES definition; increase in the number of system assets covered under the definition; increased registrations that LIPA will be required to make as a result of the definition change; various compliance activities that the Company, as the service provider for LIPA, will need to perform; increased frequency of audits that LIPA will be subjected to; and number of management and union man-hours it estimated would be needed (and the overall cost) to accomplish the tasks (PSEG BOE, pp. 30-35). The Company also references two exhibits admitted into the record (Exhibits 68 and 70) as support for its claim that the DDRR improperly rejected its request for the $900,000 to cover incremental annual labor to perform the mandatory compliance work (Id.).

DPS Staff restates, with respect to the increased staff funding, that the Company failed to adequately explain why the initial productivity savings of $1.3 million was reduced to $600,000 (DPS RBOE, p. 33). It asserts, therefore, that PSEG LI has not supported funding at any level, but DPS Staff does support funding of $450,000 (Id.).

As noted in the DDRR, the principal concern with the record on this issue is that PSEG LI did not provide adequate support for how it arrived at the new positions that it says are needed. PSEG LI provided a brief description in its testimony regarding the compliance functions that the new employees would be performing and identified in an exhibit (Exhibit 68) the number of annual labor hours it determined to be expended, by applicable compliance standard. However, the Company did not provide any workpapers or other evidence demonstrating how it determined the annual hours needed to perform each compliance function. Thus, notwithstanding the question of whether PSEG LI adequately explained why the initial productivity savings of $1.3 million was reduced to $600,000, we have no way to ascertain whether PSEG LI cost projections are reasonable and have no reasonable basis to recommend a change in the BES staffing allowance from that reported in the DDRR.

REV Staffing

As reported in the DDRR, PSEG LI requested $900,000 of incremental costs to identify and analyze alternative solutions related to the Reforming the Energy Vision (REV)[44] initiative in 2016, 2017, and 2018. DPS Staff recommended that these costs be eliminated from the revenue requirement, and instead be

[44] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

recovered either (1) as an offset against savings that would be realized as a result of implementing the selected REV alternative solution(s) or (2) through the DSA.

DPS Staff explained that PSEG LI identified eight projects in its 2016-2018 capital budget for which REV alternative solutions may be substituted. Costs for these eight transmission and distribution (T&D) projects ($142.35 million for capital expenses and $5.11 million for operating expenses) are included in the revenue requirement. DPS Staff and PSEG LI observed that any REV alternative solution that may instead be implemented in place of these more traditional solutions will have been determined to have a positive benefit cost analysis (Tr. 1279-80, 1506). In light of these factors, DPS Staff recommended that the savings resulting from any lower cost REV alternative solution(s) that is selected be used to offset costs incurred to evaluate the REV alternatives. DPS Staff also proposed that any savings (in the form of lower debt costs) that result from using REV alternative solutions be returned to customers through one of the proposed cost adjustment mechanisms, such as the DSA. Finally, in the event that the rate revenues that are provided for the more conventional T&D solutions are determined to be insufficient to offset any verified costs attributable to the analysis of REV alternative solutions, DPS Staff recommended creating a deferred asset, financing the cost of the asset, and allowing for the recovery of the additional finance costs through the DSA (DPS IB, pp. 49-50; DPS RB, pp. 35-36).

PSEG LI objected to DPS Staff's recommendation to exclude $900,000 of proposed incremental costs from the revenue requirement. It asserted that funding is needed now because REV alternatives analysis is additional to and different from the analytical work that is performed with respect to conventional

T&D projects. PSEG LI added that such work will need to be performed now, regardless of whether an alternative is ultimately selected. PSEG LI also asserted that it cannot simply reallocate funding from the conventional solutions because such solutions likely would be amortized over a longer period (e.g., 30 years), whereas a REV alternative solution may be treated as an expense (not an asset) or have a shorter asset life than a conventional solution (e.g., smart meters vs. conventional meters) and be recovered over a shorter period of time than a conventional T&D solution (PSEG IB, pp. 55-57).

The DDRR recommended the adoption of DPS Staff's proposal. In so doing, it noted that PSEG LI's panel acknowledges that the costs of analyzing the REV alternative solution may be included as part of conventional project costs (Tr. 1033). It also observed that (1) there was uncertainty as to the timing and implementation of possible REV alternatives and (2) the exhibits (69 and 70) and testimony (Tr. 1031-33) cited by PSEG LI in support of its assertion that it intended to identify only the incremental cost of the REV alternatives analyses fell short of providing the type of information that clearly and adequately demonstrates that the $900,000 amount that PSEG LI proposes is incremental to the amounts already reflected in the revenue requirement. Furthermore, it found that the cited evidence did not provide any indication of when such costs will actually be incurred (DDRR, pp. 41-42).

The DDRR also concluded that the proposal recommended by DPS Staff would address PSEG LI's cost recovery concerns by providing for cost recovery regardless of when, or if, a REV alternative solution is selected. It stated that DPS Staff's recommendation addressed the scenario wherein the $147.46 million "proxy" amount (consisting of $142.35 million for capital expenses and $5.11 million for operating expenses related to the eight conventional T&D projects) proved insufficient for covering costs of analyzing REV alternatives. It also stated, in relevant part, that:

> If the revenue requirements for the eight projects that may be replaced by REV alternative solutions are determined not to be sufficient to cover verified, incremental REV alternative costs, then the Company should be permitted to establish a deferred asset, finance the cost, and recover the additional finance costs through the DSA.[45] To the extent that any rate mechanism is used to reflect such costs or savings, the related changes to such mechanism should be reviewed by DPS prior to being approved (Tr. 1505).

PSEG LI excepts, asserting that the DDRR failed to recognize the incremental nature of its REV staffing needs. On exceptions, PSEG LI cites the same testimony that was reviewed and previously found to be lacking (DDRR, pp. 39-42). We are aware that the requested amount was characterized as "incremental" but how that cost was calculated, whether it was properly calculated and whether it would be actually incurred when indicated was not adequately demonstrated by the record evidence that the Company cited. Since it offers nothing more than it previously offered to support its position, we recommend denying the exception.

PSEG LI also claims that it is unclear why the DDRR assumes that the DSA is an appropriate mechanism to recover the funds necessary to support the REV O&M function, given that the enumerated purposes of the DSA are limited to debt cost recovery, storm cost reconciliation and certain power supply cost recovery (PSEG BOE, p. 36-37). As stated in the DDRR, the

[45] The DDRR noted that this proposal is consistent with PSEG's proposal that savings (i.e., lower debt costs) that result from using REV solutions would be returned to customers through adjustments to the DSA (Tr. 1278-79) and provides for symmetrical treatment with respect to cost and savings (DDRR, p. 42, n. 40).

reason for assuming that the DSA is an appropriate mechanism for recovering any additional financing costs that would be incurred if LIPA decided to finance any verified, incremental REV alternative staffing costs is because the DSA, as acknowledged by PSEG LI, may be used to recover debt costs. However, if the DER Rider is the more appropriate recovery/passback mechanism, then we recommend that it be utilized, provided that if it is utilized to reflect any such REV costs or savings, any related changes to that mechanism are reviewed by DPS prior to being implemented.

Enterprise Resource Planning System (ERP)

In its initial brief, Nassau County asserted that Enterprise Resource Planning system (ERP) costs of roughly $38 million should be borne exclusively by PSEG LI, not the LIPA ratepayers, and that, if any such costs are borne by ratepayers, the costs should be limited to the costs of additional software licenses, hardware, and customization of written procedures. The County added that, if such costs are legitimate, they should have been the subject of a request for proposals, thereby assuring a choice of alternate proposals and resulting in additional ratepayer savings (Nassau IB, pp. 9-10).

PSEG LI responded by highlighting, *inter alia*, testimony, which explained that the ERP system is in the 2015 capital budget and thus does not form a part of this rate plan (Tr. 1409) and that the capital budget for 2015 was approved by LIPA as part of its normal processes and was subject to public scrutiny and hearings (Tr. 1409-10). PSEG LI noted its testimony that capital expenditures such as this do not translate one-for-one into revenue requirement, instead only the annual debt cost is recovered in rates. Given that LIPA’s borrowing cost is less than 5 percent, it argued that, even if the County were correct that ERP costs “should be the responsibility of PSEG LI," the rate effect of the ERP is not the capital cost but only the debt service on that capital cost (Tr. 1410). Lastly, PSEG LI noted its testimony that the County's interpretation of the OSA is incorrect, noting that the OSA provides for PSEG LI to be compensated for all costs incurred in performing Operations Services, under OSA Section 4.2, which include, *inter alia*, the cost of capital improvements needed to provide LIPA with the requisite information systems to track, among other things, financial data, which is what the ERP does (Id.).

Based on the foregoing, the Senior Advisory Group found that PSEG LI's rebuttal testimony provided ample and persuasive justification for rejecting Nassau County's position regarding ERP costs (DDRR, pp. 42-43). There were no exceptions to this finding.

Productivity

A dispute arose in this case between DPS Staff and PSEG LI as to the nature and extent of a "productivity adjustment" to be imposed on PSEG LI's budget forecasts. In its original filing, PSEG LI proposed a productivity adjustment as a self-imposed goal intended to contain increases in its operating expenses (Tr. 77, 444). According to PSEG LI, this was a cap imposed by management on the totality of labor and non-labor increases forecasted in the Company's budgets, and amounted to $626,774 in 2016, $1.9 million in 2017, and $4.7 million in 2018 (Tr. 444).

Upon reviewing the filing, DPS Staff proposed instead to calculate a productivity adjustment using "the long standing method used by the Department" (Tr. 77), one "routinely used by the Department in electric, gas and water rate filings" (Tr. 78). DPS Staff explained that its adjustment was calculated as the one percent of the sum of labor and benefits expenses, applied to offset total operation and maintenance (O&M) expenses for each of the three rate years (Id.). DPS Staff then compared its calculation to the Company's, and found that the Company's method "fell short of the standard" by $1.7 million in 2016 and by $469,000 in 2017 (Id.). Therefore DPS Staff imposed adjustments in those amounts. For 2018, however, DPS Staff found that the Company's adjustment "exceeded the standard and therefore no adjustment is warranted" (Id.).

In rebuttal and in its briefs, PSEG LI opposed the DPS Staff productivity adjustment. Alternatively, it suggested that, if the DPS Staff productivity adjustment methodology were followed, it should be followed consistently for all three years, which would produce an upward adjustment in 2018 of $2.7 million (Tr. 445; PSEG IB, p. 73). Otherwise, PSEG LI asserted, DPS Staff's proposal to use its higher assumptions to reduce revenue requirement in 2016 and 2017 but then to use PSEG LI's assumption of higher productivity in 2018 amounted to a "heads I win, tails you lose" approach (PSEG IB, p. 73).

PSEG LI first argued that no productivity adjustment should be imposed in this case because, the Company argued, such an adjustment would be contrary to both the OSA and the LRA (PSEG IB, pp. 67-71). This was so, PSEG LI argued, because the productivity adjustment is an incentive mechanism inappropriate to apply to a public authority like LIPA that is not an investor-owned utility. Moreover, the Company argued, PSEG LI's rights and obligations as the service provider are governed by the OSA, pursuant to which labor costs are "passed through" from PSEG LI to LIPA. Imposing a productivity adjustment would constitute an impermissible amendment of the OSA, or else it would fail to reimburse LIPA for actual costs paid to PSEG LI.

In the DDRR, the Senior Advisory Group concluded that PSEG LI belied its own arguments by imposing a productivity adjustment on itself. PSEG LI started with projected budgets for the years 2016-2018 for labor and non-labor, and then imposed an escalating productivity adjustment over the three years to reduce the forecast budgets during the period. The DDRR concluded that, by doing so, PSEG LI acknowledged that building an efficiency incentive into LIPA's rates for the coming period was an appropriate means for cost curtailment on the part of PSEG LI in performing its operations under the OSA. Consequently, the DDRR rejected the argument that a productivity adjustment was inherently inconsistent with the process of evaluating rates in this matter.

PSEG LI further argued that DPS Staff's productivity adjustment was too high, because it failed to take account of PSEG LI's alleged undercounting of employees that will be necessary to ensure compliance with FERC's new rule regarding the definition of the bulk electric system (PSEG IB, pp. 72-73). However, the DDRR found that offsetting the productivity adjustments with known savings was contrary to the nature of the adjustment, which is expressly designed to apply to undefined savings that have yet to be identified. Therefore, the Senior Advisory Group was not persuaded that DPS Staff's adjustment was necessarily overstated for this reason.

PSEG LI further challenged the DPS Staff adjustment on the ground that DPS Staff used an inappropriate base number for labor and benefits in calculating the adjustment (PSEG IB, p. 72). The parties acknowledged that DPS Staff's calculation was applied to the GAAP costs (accrual accounting) calculated for PSEG LI's labor and benefits, whereas PSEG LI's request was based on ERISA funding obligations for pensions and cash accounting for OPEBs. As a consequence, the Company asserted, DPS Staff applied its adjustment to a quantity of costs that had previously been removed from the revenue requirement forecast in this matter. According to DPS Staff, however, at least in the case of OPEBs, funding is a "use of funds" in PSEG LI’s projected operating and capital budget, increasing the need for LIPA to externally finance operations (DPS RB, p. 21). The fact that this funding was recovered via financing costs versus expense recovery was a distinction without a difference, said DPS Staff. The Senior Advisory Group agreed that DPS Staff's rejoinder made sense. If the total against which the Department would normally make a productivity adjustment was merely moved from one recovery allowance to another, the DDRR concluded that did not negate the validity of the adjustment. Therefore the DDRR did not reject DPS Staff's adjustment on that basis.

The DDRR did reject DPS Staff's acceptance of PSEG LI’s 2018 productivity adjustment, however, in order to provide for consistent treatment across all three years of the rate plan. It concluded that consistency dictated that the one percent figure as calculated by DPS Staff be applied for all three years of the proposed rate plan. Such application would result in adjustments of $2.361 million in 2016, $2.395 million in 2017, and $2,443 million in 2018. In contrast, PSEG LI's adjustments were $0.627 million in 2016, $1.927 million in 2017, and $4.701 million in 2018.

The Company asserted that its own productivity imputation was a higher total over the three years than DPS Staff's adjustment (PSEG IB, pp. 73-74). Because the Company’s adjustment was weighted toward the third year of the rate plan, however, the DDRR found that it was not correct that the Company’s adjustment would result in higher savings for ratepayers over the three years of the rate plan. On the contrary, the DDRR said the cumulative impact of DPS Staff’s adjustment represented greater ratepayer benefits, even with its modification of the 2018 imputation. Pursuant to the

Department’s mandate to recommend rates set at the lowest level consistent with sound fiscal operating practices, the DDRR found that the DPS Staff methodology should be applied consistently throughout the three-year period. The resulting adjustments were ($1.735 million) in 2016, ($0.469 million) in 2017 and $2.257 million in 2018.

Both PSEG LI and DPS Staff take exception to the DDRR recommendation. Each continues to argue for its original position, PSEG LI for its self-imposed productivity adjustments and DPS Staff for its adjustments to 2016 and 2017 but for the higher PSEG LI adjustment in 2018.

PSEG LI reasserts that the very nature of a productivity adjustment is antithetical to the LRA and the OSA. It argues that the DDRR reasoning suggests that, if PSEG LI had not set a productivity hurdle for itself, there would be no basis for a productivity imputation, and it is inappropriate to punish PSEG LI for attempting to set productivity gains for itself (PSEG BOE, pp. 39-40). It argues further that this standard tool of incentive ratemaking for IOUs should be inapplicable here, where the OSA has stringent productivity and efficiency incentives that substitute for such an adjustment (PSEG BOE, p. 40). According to PSEG LI, the adjustment is tantamount to denying recovery of validly incurred expenses, contrary to the OSA and LRA.

PSEG LI also repeats its arguments that, if a productivity adjustment is imposed, it should be calculated with an eye to ever-increasing productivity over the three-year rate plan, as PSEG LI’s adjustment was, to reflect PSEG LI’s increasing familiarity with the LIPA system and service territory. Moreover, the calculation should exclude the pension and OPEB costs that were removed for ratemaking purposes. Finally, it should be offset with known savings such as costs to be incurred to meet new BES requirements that were not claimed by PSEG LI in its rate filing (PSEG BOE, pp. 41-43).

For its part, DPS Staff argues against the DDRR's recommendation to apply a one percent reduction consistently in all three years. It notes that the productivity adjustment is a proxy for anticipated overall productivity gains (DPS IB, p. 6). It characterizes PSEG LI's self-imposed budget caps as analogous to the productivity adjustment, because they are not supported by specific cost cutting measures but rather are a means to spur additional productivity (DPS IB, p. 7). Where the Company's projection is higher than one percent in 2018, DPS Staff argues, there is no need to apply an adjustment to reach the one percent proxy level, as there was in the first two years of the rate plan, but failing to adopt the Company's estimate deprives ratepayers of additional productivity savings that could be realized. DPS Staff expresses the fear that PSEG LI will thereby be discouraged from seeking to maximize its possible productivity savings (DPS BOE, p. 7).

In its brief opposing exceptions, DPS Staff continues to assert its position and to oppose PSEG LI's exceptions to the extent inconsistent with the DPS Staff position, although DPS Staff does not further elaborate (DPS RBOE, p. 19). PSEG LI's brief opposing exceptions reiterates the argument, asserted in its post-hearing briefs, that the Staff position is internally inconsistent, in that the Staff witnesses on the Policy, Overview and Revenue Requirement Panel testified that productivity enhancements may be difficult for PSEG LI to achieve until later in the transition of operational control from National Grid to PSEG LI, whereas the Inflation, Productivity and Management Audit Panel recommended the blanket productivity adjustment across all three years of the rate plan (PSEG Reply BOE, pp. 5-6). PSEG LI further argues that the same witnesses testified regarding the recommendations of the Northstar Audit, and that, if the audit had identified significant productivity improvements, the panel would be expected to address them, but did not (PSEG Reply BOE, p. 6).

PSEG LI's complaints about the productivity adjustment are all predicated on its assumption that, with the adjustment in place, it will incur future expenses for which it will not receive compensation. This assumption is a false one. The purpose of the productivity adjustment is to provide proper incentives for PSEG LI to avoid incurring expenses in the future by operating efficiently. The Department's many years of regulatory experience have taught us that no amount of close auditing and regulatory scrutiny can capture all the appropriate cost-cutting measures that a regulated entity can take, and that a modest productivity imputation of one percent of the budget for labor and associated benefits is a far more effective way of ensuring operating efficiency. Even if, as PSEG LI asserts, the OSA and its metrics represent a more detailed regime than the regulatory oversight exercised by the Department over investor-owned utilities, such contractual provisions do not substitute for the day-to-day operational decisions that can be made by on-site managers with strong efficiency incentives. We see the productivity adjustment as a regulatory tool that is appropriately complementary, not contrary, to the OSA.

Nevertheless, the Department is persuaded to overturn the DDRR recommendation on productivity imputation and instead adopt PSEG LI's productivity proposal. Both DPS Staff and PSEG LI agree that productivity gains may be more difficult for PSEG LI to achieve until later in the rate plan, due to the transition of operational control from National Grid to PSEG LI. PSEG LI's proposed productivity adjustments are consistent with this concept, as PSEG LI proposes to phase in increasing levels of productivity each year.

Moreover, further analysis reveals a miscalculation in the DDRR's conclusions. The DDRR found that a one percent adjustment made each year would yield greater benefits for ratepayers than would the Company's imputation, due to a faulty assumption that the benefits would become embedded in each year's rates and accumulate throughout the rate plan. We have analyzed the revenue requirement impacts over the three years of the DDRR productivity recommendations as well as PSEG LI's proposal and found them to be nearly identical in ultimate effect. Both approaches will yield cumulative ratepayer benefits of approximately $7.2 million over the three-year rate plan term. Given these factors, we reject the DDRR's adjustment and recommend adopting PSEG LI's original proposal.

Escalation Factors/Inflation

The parties' original positions reflected significant disagreement over the proper rates by which to escalate union labor wages; management salaries; medical and prescription drug expense and other fringe benefit costs; insurance costs; and other business services expenses. PSEG LI offered testimony from its Wages, Salaries, and Benefits Panel that union employee wages were forecast using increases included in the Collective Bargaining Agreement to take place in February 2015 and 2016; thereafter, it applied the forecasted rate of inflation to wage levels that would be effective on November 14 of 2016, 2017, and 2018 (Tr. 821; PSEG IB, pp. 79-80). As to nonunion management, administrative, supervisory and technical (MAST) employees, the same panel testified to annual budget increases of 3 percent for salaries based on its "review of various compensation surveys of projected merit and total salary increase budgets, as well as a review of past history" (Tr. 826-27; PSEG IB, p. 80).

PSEG LI calculated the benefits for all employees by escalating known costs by various factors (Tr. 827-28; PSEG IB, pp. 80-81). Medical and prescription drug benefits were estimated to increase annually by 6.6 percent. Dental costs were forecast to increase by 7 percent for 2015, based upon the increase from the prior period, by 15 percent for 2016, based on an existing agreement, and by 6.7 percent for 2017-18. The Company further assumed a 3 percent increase for benefits for administrative services beginning in 2017 when the existing contract expires and for its 401(k) plan. It assumed no increases for life and disability insurance cost and benefits consulting services.

Other witnesses, PSEG LI's Shared and Business Services panel, projected changes in cost for outside goods based on estimates provided by third-party advisors or that were contractually required (Tr. 664; PSEG IB, p. 81). They testified that, for example, where there were facilities leases that contain contractually determined increases, those increases were used for the forecast (Tr. 664). All other remaining business services were inflated in the aggregate by 2.9 percent for 2016, 2.3 percent for 2017 and 2.3 percent for 2018, which the Company used as its forecast of annual inflation (Tr. 664-65; PSEG IB, pp. 81-82).

In contrast, DPS Staff asserted in its testimony that none of the escalation factors proposed by PSEG LI is sufficiently justified or documented to be considered a known increase (Tr. 73). Consequently, DPS Staff proposed instead to escalate all these expense categories by the rate of inflation (Id.). Moreover, DPS Staff differed from PSEG LI in its choice of measures of inflation, preferring to use the Gross Domestic Product Implicit Price Deflator, or GDP-IPD (Tr. 74). DPS Staff’s forecast GDP-IPD inflation rates are 1.94 percent for

2016 and 2.1 percent for 2017 and 2018 (Tr. 76). As put forth in DPS Staff's initial testimony, the resulting adjustment from using DPS Staff's calculation is a reduction in O&M expense of $6.5 million in 2016, $4.6 million in 2017, and $5.3 million in 2018 (Id.).

PSEG LI charged that the DPS Staff adjustment contravenes both the OSA and the LRA (PSEG IB, pp. 82-87). It noted that under the OSA, PSEG LI has the right to pass through expenses, such as wages, benefits, and costs for outside services. It asserted that, if the DPS Staff adjustment is adopted, there will not be sufficient revenue to cover these expenses, in contravention of PSEG LI's pass-through rights. PSEG LI further argued that the Commission policy of using an inflation rate as a proxy for costs such as medical benefits cost is an incentive mechanism, and that such incentive mechanisms are inappropriate for use in evaluating the rates of a public authority with no shareholders.

In the DDRR, Senior Advisory Staff rejected this characterization of the DPS Staff adjustment (DDRR, pp. 48-49), explaining that the reason for the Department's long-standing practice of relying upon a general inflation factor to escalate costs, particularly medical benefit costs, is not to deny recovery of such costs, nor to create a stringent incentive mechanism to contain such costs to the rate of inflation. Rather, as is evident by the passage DPS Staff quotes (DPS IB, p. 34),[46] the Commission has recognized that some costs will escalate more rapidly than the rate of inflation, while others will grow less than the rate. Given that costs such as medical costs are included in the GDP deflator, that general rate of

[46] Opinion No. 94-3, Cases 92-E-1055 & 92-G-1056, Central Hudson Gas & Electric Corporation – Electric and Gas Rates, Opinion and Order Determining Revenue Requirement and Rate Design (issued February 11, 1994), p. 13.

inflation is reasonably accurate when applied to the total bundle of the Company's costs that are not otherwise known (Tr. 74-75). The primary reason for this policy is accuracy and fairness, as well as simplicity and administrative efficiency. If one category of costs, such as medical costs, is singled out to be escalated at a rate higher than the general rate of inflation, then corresponding adjustments would have to be made to adjust for the double count if the inflation rate is applied to the rest of the bundle of costs.[47]

The DDRR recognized that any known, determined costs should be factored into the Company's forecasts (DDRR, pp. 49-50), but found that the Company's forecasts were not based on known increases in the categories of cost at issue, but rather the educated guesses of Company's witnesses as to the likely cost escalations in the various expense categories. The DDRR relied on the fact that, in such a situation, the most accurate means of predicting future costs has, in the Department's experience, been simply to apply an inflation factor to all costs that are not otherwise known. The intention is not to provide LIPA with less revenue than it will need to pay PSEG LI's legitimate costs. On the contrary, the goal of this method is to provide the most accurate estimate of what those costs are likely to be. Given this rationale and the Department's long history of finding that this forecasting approach works reasonably well, the DDRR found no contravention of the OSA or the LRA, nor any unfairness to LIPA or PSEG LI.

The DDRR also supported DPS Staff's reliance on the GDP-IPD as the best measure of inflation to use for rate-setting purposes (DDRR, p. 50). DPS Staff testified that the GDP-IPD is

[47] See, e.g., Case 02-E-0198 & 02-G-0199, Rochester Gas and Electric Corporation – Electric and Gas Rates, Order Adopting Recommended Decision With Modifications (issued March 7, 2003), pp. 23-24.

a measure of the overall national economy and is, therefore, more indicative of the commercial activity of a utility than the Consumer Price Index (CPI), which is a measure of consumer activity (Tr. 74). In contrast, the DDRR found that PSEG LI had not sufficiently justified its choice of 2.5 percent (DDRR, p. 50; PSEG IB, pp. 87-88).

Employing these principles, the DDRR followed DPS Staff's approach to union wages and recommended that union wages should be increased by 2.1 percent, rather than 2.5 percent advocated by PSEG LI, for 2017 and 2018 (DDRR, p. 50). On the other hand, noting that PSEG-LI witnesses had suggested that the MAST employee escalation factor was based on compensation surveys and past history, the DDRR recommended rejection of DPS Staff's adjustment for the salaries for the MAST employees, subject to confirmation through the exceptions process (DDRR, pp. 50-51). In its Brief Opposing Exceptions, DPS Staff states that it has reviewed the compensation studies provide by PSEG LI and now agrees that MAST salaries should be increased by 3 percent per year, as initially advocated by PSEG LI (DPS Staff RBOE, p. 19). Accordingly, we affirm the DDRR position on the increase for MAST salaries.

The DDRR stated agreement with DPS Staff that costs for medical, prescription drug, dental, and benefits administration should be escalated by a general inflation factor, finding no indication in the record of known increases in these costs under contractual provisions. Senior Advisory Staff found no basis stated in the witness testimony regarding the forecasted increases in these costs other than bald statements regarding the percentage chosen to escalate each, accompanied by the general statement that cost inflation would likely increase by more than the general rate of inflation (Tr. 827-29). Similarly, where the Company assumed no increase for life and disability insurance cost and benefit consulting services, but where those assumptions are not based on any concrete contractual provision, the DDRR recommended that those costs should also be brought under the general inflationary increase.

In contrast, the DDRR found that some of the business services budgets were developed with known future costs in mind. It therefore adopted that much of the Company's business service budget that is based on long-term leases, quotes from its insurance broker, and similar information (DDRR, p. 52; Tr. 664). Due to insufficient detail in the record that would support the parsing out of those expenses from the others with which they are bundled (Exhs. 64, 65) and given the Company's testimony that the remainder of its business and shared services budget was escalated by its 2.5 percent proxy for inflation, the DDRR found that the forecast for those expenses was reasonably fairly done, except for the use of an inappropriate measure of inflation. The DDRR thus recommended a reduction in the business and shared services budget forecast by the difference between the Company's chosen inflation rate of 2.5 percent and the DPS Staff's rate of 1.9 percent in 2016 and 2.1 percent in 2017 and 2018.

The DDRR also recommended adoption of the DPS Staff adjustments to the escalation of PSEG LI's T&D, customer service, and power markets budgets. PSEG LI did not specifically respond to the adjustments with respect to those categories in its testimony, nor did the parties address the matter in post-hearing briefs. Given that PSEG LI had the burden of demonstrating the reasonableness of its requested revenue requirements and the budgets supporting that rate request and did not respond to the DPS Staff adjustment with any detail to support its escalation of the budgets in those categories, the DDRR recommended adoption of the DPS Staff adjustment as to those budgets, to the extent not otherwise addressed specifically above.

In its brief on exceptions, PSEG-LI challenges the general application of the GDP-IPD to its O&M expenses. Primarily, PSEG-LI asserts that the DDRR incorrectly relies on investor-owned utility (IOU) ratemaking policies which, the Company argues, are inapplicable here, given that the contractual mandates of the OSA replace the discretion that an IOU would have to manage its business (PSEG BOE, pp. 44-53). Further, PSEG LI asserts, because it is entitled to recover certain costs at issue as pass-through expenses under the OSA, the DDRR recommendation places LIPA in a financially precarious position as unable to fully recover those costs in rates (Id., p. 50). PSEG LI argues that in contrast to an IOU where an excessive forecast of inflation would enhance earnings, LIPA will use the excess to fund capital projects or pay down debt (PSEG BOE, p. 53) Finally, PSEG-LI defends the testimony of its witnesses as having been more fact-based than characterized in the DDRR (DDRR, p. 49-50; PSEG BOE, p. 51-52) and argues that it established a prima facie case in support of the validity of its proposed escalation factors (PSEG BOE, pp. 52-53).

In its brief opposing exceptions, DPS Staff questions PSEG-LI's argument that IOU ratemaking practices are inapplicable here. DPS Staff points out that PSEG LI is insulated from financial harm resulting from forecasting these costs in revenue requirement. This is the case since all appropriate and reasonable expenses incurred by PSEG-LI should be passed through to LIPA consistent with the OSA (DPS Staff RBOE, p. 20). Additionally, DPS Staff points out that PSEG LI's forecasted O&M expenses could result in either excess or a shortfall to LIPA if the actual expenses incurred are higher or lower than those forecasted. According to DPS Staff, shortfalls in revenues could cause LIPA to incur more debt (DPS Staff RBOE, p. 20). DPS Staff asserts that GPD-IPD is an accurate escalation factor for unknown costs as it takes into account the reality that costs increase or decrease at various rates.

We have considered all the arguments on exceptions and adhere to the DDRR's recommendations regarding escalation factors. We simply find insufficient record evidence to support the individual escalation factors proposed by PSEG-LI. Where PSEG LI provided evidence of known escalation of costs, such as where contracts fix future costs, the Department's Rate Recommendation reflects such information in forecasting the associated budget item. Where no such evidence exists, then the remaining operations and maintenance costs are grouped into a pool and those costs are forecasted to increase at the rate of the GDP-IPD. To selectively isolate from the pool certain elements, for example, health care, for separate escalation would undermine the principle of the general inflation pool; some costs will be above and some will be below the inflation rate. To allow selective elimination in this regard could result in an overestimation of the escalation of these O&M costs, thus requiring ratepayers to pay more than necessary in the first instance.

Customer Outreach Budget

PSEG LI presented evidence of an overall customer service budget escalating from $95.7 million from 2015 to $124.1 million in 2016, $126.1 million in 2017 and $130.9 million in 2018 (Exh. 19). A significant portion of the increase is an accrual for OPEBs in 2016 valued at over $17 million. Factoring out the OPEB accrual, the budget increase is driven primarily by over $7 million in programmatic increases between 2015 and 2016, including $2 million for "additional customer education material and notices" (Id.). DPS Staff generally supported the increased number of customer services employees and expenses to support these programmatic changes, with a notable exception of the $2 million for customer education materials.

The $2 million for the additional customer education material represents a 63 percent increase in PSEG LI's customer outreach budget, from $3.335 million budgeted in 2015 to $5.435 million in 2016. Thereafter, PSEG LI escalated its budgets by an additional 3 percent for 2017 and 2018 (Exh. 85, SCSP-1, p. 59 of 234). Of the $2 million increase, several categories stand out for the dramatic changes in proposed spending. Specifically, PSEG LI proposed to increase its storm communications budget from $18,000 to $138,540, its financial assistance communications from $7,500 to $47,725, and educational videos, distributed on its website and through its community partner program, from $100,000 to $303,000. PSEG LI proposed to increase its direct-mail budget from $200,000 in 2015 to $939,000 in 2016. For its media budget, PSEG LI proposed to increase its budget of $1.7 million in 2015 to $2.578 million in 2016 (Id.).

Responding to PSEG LI's initial testimony, DPS Staff's Customer Service Panel recommended reductions in budgeted amounts in the direct mail and media categories. Within the direct mail budget, DPS Staff proposed to disallow one direct-mail effort to all customers at $363,000 and targeted mailings on online services and customer care programs at $240,000 (Tr. 627; Exh. 85, SCSP-1, p. 59 of 234). In the media category, DPS Staff proposed to disallow nearly the entire $878,000 increase, with adjustments of $327,000 for TV campaigns and $550,000 for increased media outreach. In total, DPS Staff's adjustment would reduce PSEG LI's requested increase by $1.48 million (Tr. 627).

DPS Staff articulated a number of reasons for its proposed adjustments. DPS Staff cited to its Exhibit 85, SCSP-2, as the backup for its calculations. However, that exhibit showed DPS Staff's calculation of total LIPA revenues, multiplied by 1/25 of one percent, as equivalent to $1.5 million. DPS Staff went on to refer to the Commission's 1977 Statement of Policy on Advertising And Promotional Practices Of Public Utilities, 17 NYPSC 1-R (February 25, 1977), which states that a utility should be allowed to allocate between 1/25 and 1/10 of one percent of its operating revenues to conduct institutional advertising.

Separately, responding directly to a question as to why DPS Staff is recommending the negative adjustment to PSEG LI's outreach budget, DPS Staff stated that PSEG LI had not justified the need for the full increase nor provided a clear illustration of how the increase would be allocated toward positively impacting outreach efforts beyond funding more advertisements (Tr. 628). Picking up on this theme in support of the DPS Staff adjustment, SCC stated that "the justification furnished by the applicant of needing to improve customer approval ratings in order to meet OSA incentive metrics is self-serving, and ultimately reveals very little justification for the additional expenditure, other than to support the applicant's opportunity to be additionally compensated, and to avoid penalty or termination within the framework of the existing agreement" (SCC IB, p. 6).

On rebuttal, PSEG LI stated that the "overall reasoning" for its proposed increase to the outreach budget was that "[t]he current level of outreach communication spending by PSEG LI is not enough to move the utility from the fourth quartile of the J.D. Power survey into the first quartile" (Tr. 1373). Therefore, PSEG LI continued, "A step-change in communication investment is required in order to change customer perception, increase customer recall of utility communications and move the utility into a first quartile customer satisfaction ranking" (Id.). PSEG LI then went on to testify at great length regarding the J.D. Power survey results of customers' impressions, the importance of the metric, and how increased spending would improve customer perceptions (Tr. 1373-84).

PSEG LI responded directly to the reference to the 1977 Advertising Policy Statement by stating that the information it intended to provide will help customers manage and save on their electric bills and promote self service channels for customers to save time and allow the utility to shed operational costs in the future (Tr. 1380). Moreover, the rebuttal testimony concluded, the outreach budget would ensure that PSEG LI fulfills the mandate that it become the "brand," or face, of electric utility service on Long Island (Tr. 1380).

On brief, PSEG LI argued that the provisions of the OSA require an increased budget as necessary to meet its performance metrics. It asserted that the 1977 Advertising Policy is inapplicable, because the policy governs the balance between ratepayer and shareholder interests. Because LIPA has no shareholders and PSEG LI is not a utility as defined under the LRA, the Advertising Policy has no application here, PSEG LI said (PSEG IB, p. 101). Moreover, even if the Advertising Policy were applicable, PSEG LI argued that the activities for which it sought a budget increase are permissible expenditures of outreach funds under the policy. Granting it less than the amount necessary to meet its metrics would be inconsistent with the authority granted to PSEG LI under the OSA, it asserted. Further, it stated that it provided sufficient supporting information to justify its costs, explaining how its testimony showed the efficacy of communication via direct mail and mass media (PSEG IB, p. 103-04).

In its reply brief, PSEG LI argued further that it presented voluminous material to DPS Staff regarding a detailed explanation of the purposes of the outreach budget dollars and how that spending benefits customers. It noted that DPS Staff only requested this information after submission of PSEG LI's rebuttal testimony, and that the Company provided answers within three days. The Company complained of the ALJs' ruling denying it permission to introduce these information request answers into the record at the hearing, and submitted that they would show, in detail, how the outreach dollars would benefit consumers (PSEG RB, pp. 42, 44-45).

In its reply brief, DPS Staff noted that it was supporting an increase of $619,000 in PSEG LI’s outreach budget for the first year. DPS Staff pointed to the Company's continual assertions that the need for the increase was based upon its desire to improve its customer satisfaction score, but stated that the Company had not demonstrated how the dollars will benefit and educate the consumer. According to DPS Staff, the Company met or exceeded all of its customer metrics for 2014 and is on track to meet the metrics in 2015 (Tr. 1301, 1305-08). Therefore, DPS Staff argued, satisfying the OSA metrics in the future should not require additional funding.

DPS Staff further asserted that the Commission's Advertising Policy Statement was not the sole basis for DPS Staff's proposed adjustments to the budget. Rather, DPS Staff said the policy is relevant to DPS Staff's recommendation that PSEG LI implement measures to properly identify spending in that area. DPS Staff argued that PSEG LI's concerns about improving public opinion would be better met through improved performance on customer service, rather than mass marketing. According to

DPS Staff, performance on the J.D. Power survey is a function of customers receiving improved services, not the other way around (DPS RB, p. 28).

Based on this record, the recommendation in the DDRR was to adopt the DPS Staff-recommended adjustments. The Senior Advisory Group agreed generally that PSEG LI has not adequately justified the need for such a dramatic increase in outreach spending. It agreed further that the spending targeted particularly at mass media and direct mail was not justified by PSEG LI's record evidence explaining the reasons for it.

The DDRR did not resolve whether the Commission's Advertising Policy Statement is directly applicable here. As a general matter, the DDRR characterized the Policy Statement as a fairly obvious statement that ratepayers should not pay excessive amounts for advertising designed to make them more favorably inclined toward the utility. Rather than representing only a balance between shareholder and ratepayer interests, the Senior Advisory Group said the Policy Statement represented a general truism about what should reasonably be considered part of the utility service that ratepayers should be expected to pay for. Beyond that general rule, however, the DDRR found no record basis for applying the Advertising Policy to PSEG LI's outreach budget. Because the Policy Statement is based primarily on the nature of the messages produced by a utility – whether they are educational or designed to improve the utility's image – the Senior Advisory Group said they would have to have a complete breakdown of PSEG LI's entire outreach activities, with all messages grouped as to whether they are proper for ratepayer reimbursement or not, and all the dollars for labor, outside services, media purchases, etc. allocated between each.

Only at that point would they have been able to see whether PSEG LI's total spending on so-called "institutional advertising" is below or above the $1.5 million calculated by DPS Staff. No such evidence exists on this record, and establishing such evidence would require far more regulatory effort than is warranted for the dollars at stake. Consequently, the DDRR recommendation was not based on reliance on the Advertising Policy Statement.

The DDRR assumed that the customer satisfaction metric is designed to ensure that PSEG LI provides good customer service. The DDRR concluded that here, the purpose of the metric seems to have become distorted, such that the metric has become an end in itself, rather than a measure of the more important goal of serving customers well. The DDRR found that PSEG LI had not justified its need for the additional outreach spending, because PSEG LI's primary justification was that the spending would help it do well on the surveys, not that it would improve actual customer service.

The DDRR noted further that it was likely that most, if not all, of the messages that PSEG LI intended to distribute through its proposed mass media and direct marketing campaign would indeed be appropriate educational messages, designed to help customers with goals such as increased energy efficiency or more efficient bill payment or safety, and the like. (For this reason, the Advertising Policy Statement, focused as it is on the content of the messages, was not particularly helpful in deciding the issue here.) But merely demonstrating that the messages are appropriately educational and would be helpful was not sufficient to demonstrate that they are necessary or that the dramatic spending increase is a warranted ratepayer expense, the DDRR said. It concluded that DPS Staff's adjustments, targeted at the direct mail and media categories of PSEG LI's spending, represented appropriate reductions to these campaigns (See Exh. 85, SCSP-1, p. 59 of 234).

PSEG LI takes exception to the DDRR's recommendation, averring that the recommended customer outreach budget is insufficient to improve customer service and is inconsistent with the OSA. PSEG LI asserts that the DDRR sanctioned a reduction to the customer outreach budget to conform to the Commission's Institutional Advertising Policy Statement, but that the policy is inapplicable to PSEG LI, which has a fundamentally different role from that of an investor owned utility (PSEG BOE, pp. 7-8). PSEG LI's brief is critical of the DPS Staff position taken below, asserting that DPS Staff ignored the extensive evidence supporting PSEG LI's direct mail and mass media advertising campaigns (PSEG BOE, p. 55-57). PSEG LI then asserts that, in adopting the DPS Staff position, the DDRR similarly ignored the record evidence (PSEG BOE, p. 56). PSEG LI renews its complaint, raised below, that the evidentiary record should have included its responses to certain DPS Staff Interrogatories that PSEG LI attempted to introduce at the hearing. PSEG LI argues that the excluded material provides further supporting information on the basis of the outreach program and the proposed budgets (PSEG BOE, p. 59).

PSEG LI further argues that the OSA requires an approach different from that of investor-owned utilities, in that PSEG LI commits to linking its name with improved performance for the customers of Long Island (PSEG BOE, p. 60). It cites to a comprehensive management audit of LIPA performed by NorthStar Consulting Group which, it says, recommended a significant expansion of customer outreach efforts (PSEG BOE, pp. 60-61). It argues that its proposed expansion of outreach efforts, particularly through mass media and direct marketing, is consistent with both the OSA and the NorthStar Report, and that such efforts are necessary to meet the metric to become a "first quartile" utility as measured by the J. D. Power customer satisfaction survey (PSEG BOE, pp. 60-62). If the Department believes that metric is no longer desirable, PSEG LI writes, it should go on record to advocate for an amendment to the OSA to modify the metric, rather than disallowing the funding necessary to achieve it (PSEG BOE, p. 62).

DPS Staff opposes PSEG LI's exceptions. In response to PSEG LI's arguments about the OSA, DPS Staff asserts that PSEG LI's contractual obligations are nevertheless subject to the LRA's legal standard requiring rates at the lowest level consistent with sound fiscal operating practice (DPS Reply BOE, p. 21-22). DPS Staff repeats that PSEG LI's proposal is predicated on the continual advancement of its own performance with respect to an incentive-based metric, while ratepayers would benefit if PSEG LI corrected perception through its performance of the customer service function (DPS Reply BOE, pp. 23-26). DPS Staff asserts that a goal of the LRA was that PSEG LI be identifiable as the service provider to ratepayers and that PSEG LI is no different from other investor owned utilities in this respect (DPS Reply BOE, pp. 24-25).

PSEG LI's exceptions are denied, and the DDRR is affirmed. The Department's final recommendation is that PSEG LI's outreach budget request be reduced by $1.48 million. Contrary to PSEG LI's accusations, the DDRR recommendation was based on a thorough and careful review of all the record evidence. PSEG LI placed into evidence extensive testimony and exhibits regarding the J.D. Power Survey; PSEG LI's goal of improving its score on the survey, consistent with its OSA metric; and the beneficial impact that increased customer communications could have on the survey results. These materials were read and analyzed by the authors of the DDRR, and they have been reviewed again in the process of arriving at this Department recommendation. Nothing, however, in PSEG LI's presentation on exceptions causes us to change our evaluation of the evidence.

What is lacking on the record, and what would appear, from PSEG LI's offers of proof, to be lacking even if the excluded discovery responses were considered, is evidence that the spending increase is necessary, as opposed to merely beneficial or desirable, to improve customer service or customer satisfaction, as opposed to survey results. PSEG LI has failed to establish any causal links to tie its requested spending to an outcome worth the price to ratepayers. The purpose of this rate inquiry is to ensure that rates are set "at the lowest level consistent with sound fiscal operating practices." Additional spending on customer outreach may indeed offer benefits to customers in the form of better understanding of utility programs and opportunities,[48] but the specific expenditures disallowed here have not been shown to be needed or to be consistent with the statutory standard for rate setting.

The Department appreciates the legitimacy of a goal that PSEG LI improve overall perceptions on Long Island, because it is important for customers to have confidence in their electric service provider. It is not our intent to impose a blanket ban on advertising. Rather, in the Department's judgment, Long Island customers are particularly concerned about

[48] We are aware that targeted marketing is important to familiarize customers with energy efficiency programs and can thereby promote adoption of energy efficiency practices. Such outreach can benefit PSEG LI's brand image as well, as consumers see PSEG LI as a partner in addressing their concerns about climate change and energy bill management. We expect, however, that the outreach associated with such programs is included in the energy efficiency budget and therefore is not affected by the adjustment recommended here.

service quality, service restoration following storms, and bills. Given these considerations, we conclude that a more focused and targeted campaign within a more modest customer outreach budget that would increase from $3.3 million to approximately $4 million, rather than the $5.4 million requested.

The Department is cognizant of PSEG LI's concerns that a more modest budget may impair its ability to enhance public perception of its brand, which could impact its J.D. Power results. The OSA contemplates that, if a particular measure does not produce the type of activity and positive outcome that is contemplated by the contract, the measure should be modified. The Department supports on-going evaluation and dialogue to make sure that, with the benefit of some experience with PSEG LI as the operator under the OSA, all the measures and metrics continue to be well calibrated to achieve their goals. As part of that process, we recommend continued assessment of how best to measure consumer satisfaction based upon the factors that customers identify as most important to them in an electric service provider.

Updates and Second Stage Filing

In prefiled testimony, DPS Staff tendered the possibility that certain fixed obligations (e.g., debt service costs, interest earnings estimates, property tax obligations and union labor) should be updated during the course of this proceeding for known changes from current estimates (Tr. 293, 552-53). It also raised for consideration the prospect of "second and/or third stage filings" to reconcile current cost estimates to actual costs, so that base delivery rates in each rate year reflect the latest and most accurate cost information available (Tr. 553-54). DPS Staff expressed a preference for information to be provided to it timely, so that appropriate changes could be reviewed and reported to the LIPA BOT in time for incorporation into the delivery rates for the next rate year (DPS IB, p. 39). It argued that incorporating the costs into the delivery rates for the next year would avoid the rate shock that may be experienced from the cumulative implementation of various reconciliation provisions (Id.).

PSEG LI and LIPA Staff agreed with updating debt costs during this proceeding for the latest known actual costs (PSEG RB, p. 40; LIPA IB, p. 33). And, responding to the DPS Staff staged filing suggestion, LIPA Staff outlined a proposal and process for a limited second stage filing (Tr. 223, 232-36). As LIPA Staff explained it, the filing would capture known changes in: 1) savings resulting from the UDSA bonds, 2) costs of debt and current interest rates; 3) PSEG LI labor costs resulting from a new union collective bargaining agreement (CBA); 4) actual payments-in-lieu-of-taxes (PILOTs) on transmission and distribution property; and 5) unanticipated costs associated with changes in federal, state or local laws, or rules, regulations and orders (Tr. 223-24; LIPA IB, pp. 34-36). LIPA Staff recommended that the format of the second stage filing follow the format of its Exhibit 5, the details of which it believes the parties do not dispute (LIPA IB, p. 36).

The Fall 2015 update for known changes would adjust the rates effective January 1, 2016. The Fall 2016 second stage filing would cover known and measurable costs for incorporation into the delivery rates for 2017 and 2018 (DPS IB, p. 38; DPS RB p. 25). LIPA Staff proposed that the stage filing process include a Fall 2017 filing, consistent with DPS Staff's recommendation, to capture further cost changes in the rates to become effective January 1, 2018 (LIPA RB, p. 25; DPS IB, pp. 38-39). LIPA Staff expressed a commitment in working with Department Staff to provide updated information in November of

2015 and ensure that the Department would have sufficient time to review it and provide a recommendation to the LIPA BOT before its December 2015 decision on the proposed three-year rate plan (Tr. 234-35).

The DDRR noted that the three parties stated they generally agree with the LIPA Staff proposal (DDRR, p. 62; PSEG IB, p. 97; DPS IB pp. 38-39, RB 25; LIPA IB, p. 36). However, the Senior Advisory Group requested clarification from the parties regarding the scope of updates and subsequent filings. In its initial brief, LIPA Staff added to the scope of the Fall 2015 update by proposing to include both property taxes and pension and OPEB costs for which it is responsible under its Power Supply Agreements (PSAs) (LIPA IB, p.33). LIPA Staff's initial brief did not mention these categories with respect to later filings. However, the attachment to LIPA Staff's reply brief included these items in all subsequent update filings. The DDRR noted that LIPA Staff would also have the Department review the proposed DSA for each rate year of the three-year rate plan. The DDRR requested that the parties comment in their briefs on exceptions on the scope of updates and second stage filings.

As explained in the DDRR, DPS Staff conditioned its agreement to include union CBA costs in the second stage filing on PSEG LI providing a "calculation of the total wages contained in its case, broken down into union and non-union employees and referenced to work papers in this proceeding, and laying out a time line as to when the information would be provided to Staff" (DPS IB, pp.38-39). Although not stated as a condition, DPS Staff also requested direct access into all modules of the Company's Systems, Applications and Products (SAP) financial system and available reporting tools, which DPS Staff argued would: 1) assist it in being able to efficiently validate actual costs; 2) expedite the review of updated filings; and 3) aid in DPS Staff’s on-going monitoring of the Company’s actual costs in relation to forecasts (Id.).

PSEG LI opposed the condition attached to DPS Staff’s agreement to the second stage filing process, as well as the request that DPS Staff get direct access to the Company’s SAP system (PSEG RB, pp. 40-41). It argued that since the impact of a new CBA would only affect union wages, demanding the Company to supply a breakdown that includes non-union wages would be superfluous (Id.). Moreover, it said that requiring direct access to all modules of the Company’s SAP system has nothing to do with the second stage filing, and LIPA Staff agreed to provide the information needed for DPS Staff to process the second filing (Id.). The Company concluded that the second stage filing should be adopted as outlined in its initial brief (PSEG RB, p. 41).

The Senior Advisory Group agreed with the parties' statement that updates and staged filings have been adopted in cases before the PSC for certain key cost components because of the uncertainty and difficulty in accurately predicting those significant expense levels over a multi-year rate plan. As noted in the DDRR, the Commission emphasized in its recent adoption of an updated cost of debt provision for Con Edison that updating the cost of debt is appropriate because it will ensure that the utility only receives the amount of revenue needed to cover its actual debt cost. Moreover, setting rates for LIPA's three-year rate plan is even more complicated by the fact that the rate filing by PSEG LI, the new service provider, is not based on historic test year information. The historic test year data, which is typically used to make comparisons to expense forecasts in the three-year rate, was unavailable. For the most part, the parties had to rely on the Company's three-year forecasts (Tr. 551).

The DDRR reflected support for the update and staged filings process, as described by LIPA Staff in its briefs. The Senior Advisory Group agreed with the DPS Staff position, that LIPA could recover the changes in debt costs, T&D payments in lieu of taxes under the DSA, if the update and stage filing process is not adopted, but to the extent practicable, these costs should be reflected in LIPA's base delivery rates.

The DDRR pointed out that although there were no objections raised by any parties to using the format in Exhibit 5 for the stage filings, LIPA Staff filed a revised Exhibit 5 on August 5, 2015, subsequent to the filing of reply briefs. The cover letter accompanying the exhibit indicates that the revisions were worked out among LIPA Staff, PSEG LI and DPS Staff; however, the other parties did not independently confirm their agreement to adopt the revised Exhibit 5. Thus, the DDRR stated that it would be appropriate for the parties explain, in the next brief filed in this matter, whether they are in agreement with the format and contents of the revised Exhibit 5.

With respect to the DPS Staff request that the Company supply a calculation of total wages, broken down into union and non-union employees and referenced to work papers, the DDRR noted that although it would have been preferable for DPS Staff to raise its request earlier in this proceeding, the request is not only reasonable but essential to the rate setting process. The DDRR discussion emphasized that consistent with the DDRR recommendations regarding inflation and other escalation factors proposed in this matter, that disaggregated information is needed to determine a final revenue requirement. The DDRR emphasized that the information will continue to be essential to evaluate the second stage filings and, therefore, recommended that PSEG LI be required to supply the information.

The DDRR also noted that the DPS Staff request, in its initial brief, to be granted direct access to PSEG LI’s SAP financial system modules, came late in the process. The DDRR explained, however, that the Department has access to the financial system modules at all of the other major electric utilities in the State. Further, the intent of the LRA is to provide regulatory oversight of PSEG LI that is as comparable as possible to that of other NYS utilities and, to this end, the statute speaks to access to books and records, which should encompass electronic records. Therefore, the DDRR recommended that PSEG LI be required to secure Department access to the SAP system, and invited the parties to address this issue on exceptions.

In the brief on exceptions to the DDRR, PSEG LI addressed its position on the format and content of revised Exhibit 5 and the DDRR recommendations for a breakdown of the total wages for union and non-union wages (MAST) employees and Department access to the Company's SAP system (PSEG LI BOE, pp. 64-65). Specifically, PSEG LI confirmed that it is in general agreement with the format and content of revised Exhibit 5, provided the breakdown of the employee wages and is working with DPS Staff to reach an agreement on providing limited access to the Company's SAP system (Id.).

DPS Staff states, in response to the DDRR, that it agrees with the components identified and discussed in the DDRR for the 2015 update and in the second and third stage filings for known changes (DPS BOE, pp. 10-11). DPS Staff outlines the process as follows:

- Fall 2015 filing: updates the 2016 base rates for known changes for the cost components identified in the DDRR. The update for debt service would be calculated using the latest known interest rates for debt, letter of credit and remarketing fees, interest income, etc.

- End of 2016 filing: actual costs related to debt service, storms, and certain power supply expenses would be reconciled and any resulting amount would increase or decrease rates through the DSA to be reflected in rates the subsequent year.
- End of 2016 filing: the year-end or second stage filing would occur to update the base rates for 2017 to reflect the amount of the DSA for 2016.
- End of 2017 filing: the DSA would be reconciled and the year-end or third stage filing will occur to update the base rates for 2018 to reflect the amount for the DSA for 2017. (DPS BOE, p. 11).
- End of 2016 and 2017 filings: the DSA would be calculated and a second/third stage filing will occur to update the subsequent years' base rates for the amount of the DSA in the prior year.
- Union labor costs would be updated at the end of 2016, upon the expiration of the CBA, by multiplying the union wages included in rates by the difference between the wage increase percentages included in the case (2.25% for 2016, 2.1% for 2017, and 2.1% for 2018) and the wage increase percentage included in the new CBA.
- Benefits and/or payroll taxes directly or indirectly impacted by the new CBA would be incorporated in subsequent updates and reconciled to the amounts included in taxes.
- PILOTs would be updated in each of the annual updates (Fall 2015, based on actual 2015 expenses; second stage filing at the end of 2016; and third stage filing at the end of 2017).
- The impact of changes in regulatory mandated costs would be reviewed during the annual updates to determine if they are on-going in nature or one-time events. If the costs are one-time events and rates are updated for the upcoming year, once these costs are fully amortized, the rates would be reduced accordingly.
- Updates for settlements and costs relating to pensions, OPEBs, and property taxes would be reviewed by Staff to determine if they are one-time events and once fully amortized, rates should be reduced accordingly.

- On-going changes to costs related to the Power Supply Agreement would be reconciled through the DSA. (DPS BOE, pp. 11-12).

DPS Staff takes issue with PSEG LI's claim that (1) it is working with DPS Staff to reach an agreement on providing limited access to the SAP system and (2) the Company is reserving its right to object to granting access and any expansion of access that is granted (DPS RBOE, p. 28). According to DPS Staff, it met with PSEG LI counsel and other personnel and identified the electronic access that would be acceptable as a starting point pending a further determination whether additional access is necessary (Id.). DPS Staff contends that it reached an agreement in principal on this issue, thus the Company's statements in the BOE are inappropriate.

LIPA Staff included a two page appendix (Appendix A) with its brief opposing exceptions. The appendix is intended to update and supersede its revised Exhibit 5 (LIPA RBOE, Appendix A). It notes that although it, DPS Staff and PSEG LI prepared the appendix jointly, some clarification is needed with respect to medical benefit costs related to the new CBA, which is expected to be in place after the existing one expires in November (LIPA RBOE, pp. 8-9). Specifically, LIPA Staff says that it may be appropriate to include known changes in these union-related benefit cost as part of the update process because the costs will be known and measurable. It notes that the current DPS Staff position does not appear to allow for recovery of medical premiums as part of the update (LIPA RBOE, p. 9). It also points out that medical benefit costs are extremely difficult to forecast and that allowing the costs to be part of the update process will alleviate most of the uncertainty about medical benefit costs, and provide more accurate projections, while reflecting the actual cost to serve (Id.).

We recommend that the LIPA BOT adopt the update and staged filings process as indicated in Appendix A to LIPA Staff’s brief opposing exceptions, the principal provisions of which are incorporated into the attached Appendix II, as further qualified by DPS Staff and discussed above. We further recommend that LIPA Staff's proposal, to provide for reconciliation of the medical premiums associated with the CBA, anticipated to become effective after November of 2016, be rejected. Updates for increased costs resulting from the new CBA should be made for direct costs, such as annual cost of living adjustments and benefits provided pursuant to the CBA relative to the amounts assumed in revenue requirements. In addition, costs indirectly impacted by the new CBA should be updated, such as payroll taxes related to the cost of living adjustment. However, employee benefit costs that are not directly impacted by the CBA, such as current premiums, should not be included as part of the update since such costs are incorporated into the pool of costs covered by general inflation (see Escalation Factors/Inflation). Permitting an update of premiums would undermine the general inflation approach to these estimated costs.

Concerning DPS Staff's access to the Company's SAP system, we see no reason to change the DDRR recommendation on this issue. In the event that DPS Staff secures the necessary access by the time that the LIPA BOT considers the rate application, there will be no need for further action.

Storm Costs and Storm Reserve

Straight Time Labor

DPS Staff initially proposed that beginning January 1, 2016, PSEG LI be required to submit a report to the Department, within 30 days after a storm event in which straight time labor costs are charged to the storm reserve, reconciling the labor costs charged in base rates to the labor costs charged to the storm reserve (Tr. 499). DPS Staff expressed concerns over how PSEG LI and LIPA would be tracking the costs and that an over-collection or double count could occur if straight time labor costs are billed to LIPA for personnel other than T&D personnel during a storm event, because the straight time for all other personnel is already covered in the base O&M budgets (DPS IB, p. 35). DPS Staff thereafter offered to extend the deadline for submission of the report until 45 days after a storm event, reemphasizing that the report would be narrowly focused to include only straight-time labor (DPS IB, p. 36; DPS RB, p. 19). In its briefs, DPS Staff clarified that it was not suggesting PSEG LI provide a report after every storm event. Rather, DPS Staff said that it "should have the option to request and receive such reports as reasonable and necessary to ensure storm costs are accounted for and allocated correctly" (DPS IB, p. 37). DPS Staff also asserted that, pursuant to the terms of the LRA, DPS has the authority to request PSEG LI to provide these reports to protect Long Island ratepayers from improper cost assignment (DPS RB, p. 19).

PSEG LI stated that, although the concerns expressed by DPS Staff are unfounded, it would not oppose providing a few randomly selected "spot" reports as a check to ensure that the storm accounting is properly managed and that there are no storm costs being double counted (PSEG IB, p. 89). According to PSEG LI, during a storm event only T&D personnel are permitted to bill straight-time labor costs to LIPA; the straight time of all other personnel is fully contained within base O&M budgets (Tr. 449). Moreover, it claimed that a double recovery of costs could not occur because incremental straight-time work charged to storms would need to be performed by contractors or additional overtime (Tr. 450; PSEG IB, p. 89). Finally, PSEG LI stated that it would need 90 days to submit a report after the storm event, as opposed to the 30 days initially requested by DPS Staff or even the 45 days in the revised offer, because the Company must first "close books on the event, make necessary reconciliations and review, analyze and investigate charges that may need clarification" (PSEG IB, p. 89; PSEG RB, p. 37).

The DDRR noted the Senior Advisory Group agreement with DPS Staff, that the scope of information requested – straight time labor – is very narrow. It also agreed with DPS Staff that this straight time labor information should be monitored and maintained by PSEG LI in a system that would allow the Company to readily produce and deliver it in a report within 45 days. The DDRR indicated that PSEG LI could note in the report if information provided was preliminary and needed further verification, and then state when it expected a final report to be submitted. The Senior Advisory Group found that submitting straight time labor reports would not present onerous workload and timing burdens on PSEG LI and that production of this type of information is consistent with the general statutory obligation of the Department to review the reasonableness of certain storm costs (PSL §3-b(3)(c)(2)).

PSEG LI notes, in its exceptions to the DDRR, that it does not dispute the PSL authorizes the Department to review and make recommendations regarding storm costs, including opining on whether the costs were prudently incurred by the Company and whether PSEG LI would be liable for the costs under the OSA (PSEG BOE, p. 64). The Company's opposition is focused on the DDRR recommendation that the Company be required to file a report in 45 days. PSEG LI argues that OSA Appendix 10 provides that storm invoices should be submitted to LIPA within three months after the end of a storm, and requiring PSEG LI to submit a report to DPS in half the time is redundant and unnecessary (PSEG BOE, pp. 64-65).

DPS Staff, pointing to the provisions of PSL §3-b(3)(c)(ii), asserts that the Department has an obligation not only to assess PSEG LI's performance in executing its emergency response plan but also to review the costs associated with the Company's performance and make recommendations to the LIPA BOT, which would include a review of costs for straight time labor (DPS RBOE, p. 29). It further states that DPS Staff never proposed the straight time labor report should be identical to the all-inclusive storm invoices indicated in OSA Appendix 10; rather, the report would cover only straight time labor, and thus would be significantly narrower in scope (Id.). DPS Staff recounts that straight time labor is limited to in-house labor that is being inputted and tracked by PSEG LI's internal systems in "near real time" (DPS RBOE, p. 30).

Nothing presented in the exceptions to the DDRR supports a change in the prior DDRR recommendation. Therefore, we support the recommendation that PSEG LI be required to submit a report within 45 days to the Department that provides the incremental straight time labor for a storm event.

Costs for Unrealized Storms

In pre-filed testimony, DPS Staff stated that, to the extent necessary, it would review all preparatory storm costs incurred by PSEG LI for storm events that do not materialize, and may make formal recommendations to the LIPA BOT regarding the reasonableness of those costs prior to the LIPA BOT authorizing payment of the costs (Tr. 501). The process envisioned by DPS Staff would involve PSEG LI’s filing a report, pursuant to a Department request, that contains a full accounting of all storm event costs incurred and the total billed to LIPA that will be charged to the storm reserve (Tr. 502).

PSEG LI stated in rebuttal testimony and brief that it supports the DPS Staff recommendation (Tr. 453; PSEG IB, pp. 90-91). The Company highlighted the uncertainty of anticipated weather events and the potential significant risk of costs that may be incurred in preparing and responding to storm events that either do not materialize or where the weather experienced is less severe than expected (PSEG IB, p. 90). It pointed out that the DPS Staff approach would mitigate certain risks, such as the Company's ability to satisfy the O&M budget metric targets (PSEG IB, p. 91). According to PSEG LI, it could be extremely difficult to satisfy that metric because costs that should be charged to the storm reserve cannot be charged if the storm does not occur, putting strains on the Company's ability to perform its normal work in accordance with parameters in the OSA (Id.). PSEG LI pledged to cooperate with DPS Staff's review of future non-qualifying storm event costs and to support DPS Staff in making recommendations to the LIPA BOT for potential recovery of storm expenses (Id.).

LIPA Staff responded to the positions of DPS Staff and PSEG LI, noting specifically that the process embraced by PSEG LI would be inconsistent with the terms of the OSA (LIPA IB, p. 41). The OSA clearly states what costs can be recovered from the storm reserve, it said, and costs that must be charged to O&M expense in accordance with the terms of the OSA cannot be reassigned to the storm reserve in violation of the OSA (Id.).

The DDRR noted that it is of great importance for PSEG LI to properly prepare for storms, and indicated support for efforts to ensure that the Company has the proper incentive to do so. The DDRR also expressed support for PSEG LI providing DPS Staff with complete information about its storm preparations and the cost thereof, even in cases where the storm fails to materialize, and DPS Staff review of such information and reporting to the LIPA BOT regarding DPS Staff's assessment of the reasonableness of PSEG LI's actions and the costs incurred. However, the DDRR memorialized the Senior Advisory Group's agreement with LIPA Staff, that the provisions of the OSA cannot be altered in this regard, so the costs for storms that do not happen cannot be eligible for recovery from the storm reserve. The Senior Advisory Group recommended that the LIPA BOT consider modifying the metric regarding the O&M budget to exclude the reasonable costs to prepare for storms that never materialize in order to ensure that the metric does not serve as a disincentive to proper and prudent storm preparation.

LIPA Staff is the only party to address this issue in post-DDRR brief. In its brief on exceptions, LIPA Staff distinguishes between the two ways that storm costs would be recovered, either through the regular O&M budget or, for very significant storm events, through the storm reserve account and the DSA reconciliation mechanism (LIPA BOE, p. 5). It asserts that PSEG LI is compensated for all of its storm costs, including preparation costs that may turn out in hindsight not to have been required (Id.). It says that recovery of costs for "unrealized storms" would occur through PSEG LI's regular O&M budget, which could cause PSEG LI's O&M expense to exceed its budget, affecting its eligibility for certain metric-based incentive compensation and providing a disincentive for PSEG LI to prepare for significant weather events (LIPA BOE, pp. 5-8). As the LIPA Staff notes, the OSA permits PSEG LI to expend up to 102% of its approved budget and still remain eligible for contract incentives (LIPA BOE, p. 8).

Regarding the suggestion in the DDRR that the budget metric might be amended to relieve PSEG LI of the risk of exceeding its regular O&M budget for unrealized storms and thereby possibly forfeiting metric dollars, LIPA Staff claims that a change in the metric would not be necessary because the OSA provides several means to resolve that concern (LIPA BOE, p. 7). One way that LIPA Staff points to is a budget amendment which, it states, would alleviate the risk that the Company would fail the budget metric and there would be no disincentive for it to prudently plan for forecasted storms (Id.). LIPA Staff cautions, however, that amending PSEG LI's approximately $550 million annual O&M budget is a significant matter. It contends that the storm preparation expense for an unrealized storm should therefore be prudent, properly managed and mitigated, and material (Id.). For the unrealized storm event expense to be considered material, LIPA Staff urges that it must be at least 2 percent of the Company's O&M budget, or about $10 million (LIPA BOE, p. 8). Finally, LIPA Staff states that LIPA would welcome the Department's review and verification of the claimed expenditures for these events.

We view the budget amendment proposal by LIPA Staff as a reasonable mechanism to ensure that PSEG LI would be able to cover the extraordinary costs incurred for the unrealized storm events. As stated in the DDRR, it is critical that PSEG LI have no disincentive to prudent utility storm preparations. With use of the budget amendment process, PSEG LI will now have confidence going into storm preparation that the costs incurred for good utility storm preparedness will not count against compliance with the O&M budget metric should the subject storm fail to materialize or be less severe.

Storm Reserve Cap

PSEG LI already employs storm reserve accounting on a limited basis under the OSA, but PSEG LI and LIPA Staff proposed an additional storm reserve account as part of this rate filing.

Based on the storm costs (excluding those major storms for which LIPA received FEMA reimbursement) over a recent four-year period, LIPA Staff calculated a four-year average of $53,248,082.17 (Tr. 502-03). It then applied a 5.7-9.5 percent annual inflation-adjusted reduction based on a strengthened and storm hardened system to project a storm reserve budget of $48.597 million, $48.169 million, $49.077 million, and $50.199 million for 2015, 2016, 2017, and 2018, respectively. DPS Staff agreed, and supported these forecasts for the annual storm reserve (Tr. 504-05).

Amounts in the storm reserve are collected through base rates (Tr. 225). As PSEG LI incurs storm costs, it charges those costs against the storm reserve. Due to the variability of storms and the method of collection through base rates, the storm reserve will sometimes carry a deficit balance and sometimes contain excess funds (Tr. 225). The storm reserve carries over from year to year, helping to smooth the variability between years (Tr. 215-16, 746-47). PSEG LI proposed that if, at the end of a "tracking period" ending on September 30 each year, a deficit remained in the storm reserve, one-third of the under-recovered amount would be recovered from ratepayers through the DSA (Tr. 746).

DPS Staff generally supported PSEG LI's proposal to collect under-recovered amounts through the DSA. To avoid the situation where the storm reserve could build up to an excessive level, DPS Staff proposed a cap on the level the storm reserve account could reach. Initially, in testimony, DPS Staff proposed to cap the total storm reserve level at 1.5 times the annual allowance for any given year, a level which approximates the highest single year (2006) storm expenses of $75 million (Tr. 511). It noted that there would be no funding cap for 2016 since collections would commence in January 2016 and could not reach the maximum level in that year (Tr. 510). And, if the collections cap were to be exceeded, an adjustment would be made to reduce the reserve balance in the account to the base rate allowance for that year (approximately $50 million), and the excess amount would be returned to customers (Tr. 225, 510).

DPS Staff, LIPA Staff and PSEG LI subsequently agreed to cap the storm reserve at $75 million annually and to return to customers amounts accumulated in excess of the cap, in the form of reduced debt borrowings (DPS RB, p. 19; Tr. 781; PSEG IB, p. 123). SCL asserted that the storm reserve funding level should be capped at the lesser of 1.5 times the rate allowance or $75 million (SCL IB, p. 13). SCL thereafter indicated that it would defer to DPS Staff on this issue (SCL BOE, p. 1). As a result, there is no continuing dispute over the funding level.

The DDRR stressed the fact that costs associated with storm events are very difficult to forecast with any degree of accuracy. And, as LIPA Staff pointed out, even with the FEMA reimbursements, over the last 10 years the unreimbursed costs charged to electric customers from these storm events have ranged from $31 million to $103 million (Tr. 215). Setting the cap at a fixed amount provides a transparent, simple and readily verifiable way to track annual storm reserve funding and ensure that funds in the storm reserve account are used for the intended purpose.

Therefore, the DDRR agreed with the parties’ proposals for a larger storm reserve account, capped at $75 million. Using any surplus funds in the account to offset future borrowings benefits ratepayers because they would not incur the additional costs and carrying charges associated with debt financings. No party took exception to this aspect of the DDRR. We, accordingly, recommend that the LIPA BOT adopt the storm reserve account as proposed.

Proposed Storm Hardening Collaborative

NYC, joined by NRDC, SCL, and SCC, recommended that LIPA and PSEG LI commence a collaborative process that will analyze system needs on a holistic basis using the most current climate projections and storm hardening design standards. NYC noted that, well before Hurricane Sandy, LIPA commenced a 20-year, $500 million storm hardening program. NYC however stated that the annual average spending of $25 million under this program was insufficient with respect to the scope and speed of deployment needed to address present climate threats to LIPA's infrastructure.

NYC also observed that PSEG LI's storm hardening activities focus exclusively on projects supported by FEMA grants, which include elevating substation components, hardening mainline distribution overhead lines, installing up to 1,350 automated switching units, hardening certain distribution lines, and replacing a limited number of transmission poles (Tr. 837, 1450-51). While acknowledging the importance of these actions, NYC said they are inadequate to protect the system against current and future climate risks. NYC said that more is needed, specifically the immediate convening of a stakeholder collaborative modeled after the one that is being conducted by Consolidated Edison in Cases 13-E-0030, et al.

NYC noted that in the Consolidated Edison collaborative, the participants discuss current and future storm hardening plans, design standards and system vulnerabilities, and provide Consolidated Edison with recommendations for program enhancements. It added that the collaborative oversees the work of a third-party consultant retained to develop a climate change vulnerability study that provides a long-range basis for the ongoing review of storm hardening design standards and addresses how temperature and humidity, temperature variability and load, precipitation, extreme events, and sea level rise and coastal storm surge flooding will impact facilities in the future (Tr. 848-49). NYC stated that the specific scope of the collaborative should be developed by participating stakeholders -- led by PSEG LI and LIPA -- but should otherwise mirror the collaborative that is being conducted by Consolidated Edison, under the Commission's supervision.

PSEG LI indicated that it would be interested in meeting with NYC, as well as other interested governmental entities and stakeholders, to discuss additional, cost-effective storm hardening that would bring increased value to LIPA customers. PSEG LI, however, opposed what it sees as NYC's efforts to dictate how the collaborative should be structured and what studies should be performed.

PSEG LI asserted that it has already conducted studies covering many aspects of the work proposed by NYC, including extreme events, sea level rise and surge flooding. It added that it has performed associated modeling, and incorporated the results into system improvements. It said it has already incorporated climatic variables into design standards, including 130 mph wind standards for new transmission and critical distribution infrastructure and design elevations for critical equipment, specifically, the higher of the 1-in-100 years plus 2 feet or the 1-in-500 years flood level elevations.

PSEG LI added that its current storm hardening activities are focused on implementing a three-year $730 million storm hardening program which must follow rigid FEMA design requirements to qualify for funding and fulfill contractual requirements of the OSA. PSEG LI expressed confusion as to how NYC's collaborative concept comports with these obligations. It adds that procurement of the "external and contractor and other resources" sought by NYC will require significant additional funding and internal resources. Thus, it said that a better understanding of the ratepayer costs and benefits, scope of the proposed collaborative and impact on existing storm hardening commitments is needed before it can commit to NYC's proposed collaborative.

PSEG LI expressed a willingness to meet with NYC representatives to review their insights and with NYC, other governmental entities, such as Nassau and Suffolk counties, and other interested stakeholders to discuss establishing a storm hardening collaborative that could inform future decisions on cost-effective storm hardening and bring value to LIPA's electric customers. It therefore concluded that there is no need for DPS to address NYC's recommendations with regard to establishing a storm hardening collaborative. DPS Staff asserted that conducting a collaborative for storm hardening would not be productive at this time and should not be explored.

Based on the foregoing, the Senior Advisory Group found that meetings with interested stakeholders to discuss current and future storm hardening plans, design standards and system vulnerabilities and to allow such stakeholders the opportunity to provide PSEG LI and LIPA with recommendations for program enhancements has the potential to improve PSEG LI's future storm hardening efforts and bring value to LIPA's electric customers. It, therefore, recommended that PSEG LI and LIPA Staff meet with representatives of DPS Staff, NYC, NRDC, Suffolk and Nassau Counties, and any other interested stakeholders to review and discuss storm hardening plans of PSEG LI. It did not recommend retention of a third party to perform studies, as no party has made a reasonable showing that the incremental benefit to current system planning outweighs the cost associated with the retention of a third party to conduct potentially redundant analysis and studies (DDRR, pp. 72-75).

There were no exceptions.

Transmission & Distribution Capital Budgets

Loading Factors

As discussed in the DDRR, PSEG LI presented T&D capital budgets of approximately $360.8, $336.6, and $382 million in 2016, 2017, and 2018, respectively (Exh. 13). To these amounts, DPS Staff proposed negative adjustments of $47 million in 2016, $47 million in 2017 and $78 million in 2018 (DPS IB, p. 16). DPS Staff asserted that the adjustments are necessary to avoid a possible double count with respect to the loaders that were applied to Administrative and General (A&G) costs and Pensions and OPEBs, and due to the Company's failure to adequately address its questions why such loaders were different from those that were previously applied (Tr. 581). PSEG LI and LIPA Staff asserted that the costs at issue are real costs incurred in capital programs (LIPA IB, p. 39).

PSEG LI acknowledged that (1) it did not provide detailed loading factors with its initial filing because sufficiently detailed information was not yet available and (2) loading factors were erroneously left out of its 2014 project estimates. However, it stated that detailed information regarding the loading factors was provided with its rebuttal filing and that such information establishes that the costs should be recovered as capital costs (PSEG IB, pp. 57-62; PSEG RB, pp. 20-26).

The DDRR found that PSEG LI provided plausible reasons in rebuttal testimony why the costs at issue should, for the most part, not be duplicative and should be recovered as capital costs (Tr. 131-36). The DDRR noted PSEG LI's explanation that: (1) the initial filing contained capital budgets that were developed in total, based on the T&D history for labor, material, contractors, and benefits, and included application of a general 14.3 percent manual adjustment loading factor to each of the projects presented in the T&D capital budget (Tr. 133); and (2) only after the approval and review process had been completed, and the SAP accounting platform had been implemented, did it have available to it the more precise and detailed budget information that it presented in its rebuttal filing, where it then identified new and incremental loading factors (DDRR, p. 75-76).

Because the costs at issue appeared to be properly classified as capital costs and designed to reflect only incremental loading factors, the DDRR recommended that they not be excluded. However, as there also appeared to be some lingering confusion and uncertainty as to whether the applied loading factors are accurate and not more than they should be, the DDRR requested that PSEG LI recheck and confirm that all of the loading factors have been fully and correctly updated and have not been applied to non-labor costs/contingency costs (DDRR, p. 76).

On exceptions, PSEG LI confirms that it has rechecked the loading factors and that all payroll loading factors have been fully and correctly updated and have not been applied to non-labor costs. PSEG LI states that A&G loadings may properly be applied to both labor and contractor capital costs, as A&G loadings follow the capital work that can be done by internal or external labor resources, adding that it has engaged in a comprehensive process to put the accounts in order based on the FERC system of accounts and load them properly in the SAP system. PSEG LI states that it does not intend to apply loading factors to any contingencies and that capital budgets for 2016 and beyond will not contain any loadings on contingencies (PSEG BOE, p. 65).

In its brief on exceptions, DPS Staff asserted that uncertainty remained as to whether PSEG LI is double counting the loading factors in 2016-2018. In its brief opposing exceptions, DPS Staff recommends that PSEG LI update its capital expenditure budgets to reflect the correct loadings.

We have reviewed the record and are satisfied that the overall T&D capital budgets of approximately $360.8, $336.6, and $382 million in 2016, 2017, and 2018, respectively, identified by PSEG LI in revised Exhibit 13 are the correct baseline from which any DPS Staff adjustments that are affirmed or approved herein should be made.

Old Bethpage Substation Construction Work

PSEG LI proposed to recover costs associated with the development and construction of the proposed Old Bethpage substation, a substation that would be fed by tapping into the proposed Plainview to Ruland Road 69 kV Transmission Line. DPS Staff asserts that LIPA's recently-issued Request for Information (RFI) to seek approximately 20 MW of capacity relief through REV type projects, could defer the proposed Plainview to Ruland Road 69 kV Transmission Line. Noting that the proposed transmission line is temporarily on hold and that the construction of the substation was contingent on the construction of that line, DPS Staff proposed an adjustment to remove the 2018 costs associated with the construction of the substation (DPS IB, pp. 26-28; DPS RB, pp. 17-18).

PSEG LI asserted that the construction, lead time and demonstrated need for the substation make it “too risky” not to include the 2018 funding amount (PSEG IB, p. 62, PSEG RB, pp. 26-27; Tr. 140, 602). It cited a Newsday article that discusses a major new housing development in the Plainview area, saying that the new load associated with this type of project will drive the need for the new substation and new transmission line regardless of any capacity obtained in response to the RFI or capacity relief through Utility 2.0/REV projects (Id.).

After recounting the foregoing, the DDRR noted that there is no dispute between the parties as to the funding that PSEG LI requested to facilitate the purchase of land and the engineering costs for the substation in 2016 and 2017, adding that the only dispute is whether the costs for construction that are proposed in 2018 should be recommended for approval. The DDRR agreed with DPS Staff that the 2018 construction costs should not be recommended for approval at this time, but requested that, in its brief on exceptions, PSEG LI clarify whether the amount at issue is $13 million, as stated in briefs, or is $9.7 million as indicated in Exhibit 13[49] (DDRR, pp. 77-78).

PSEG LI takes exception to this recommendation, arguing that it is "too risky" for DPS to assume that the load growth will not materialize or that a REV solution might be sufficient to offset the expected load growth. PSEG LI asserts that DPS Staff presented no evidence upon which to make such a determination, adding its belief that DPS is placing too much emphasis on trying to have absolute certainty for a project that would not be needed for another two and a half years.

PSEG LI states that under both the PSEG LI/Authority budgeting process, and the manner in which rates are set under the Public Power Model, there is no risk that any construction costs will be collected in rates before PSEG LI and the Authority determine that the project is needed. It indicates

[49] For purposes of calculating the revenue requirement, the DDRR used $9.7 million. PSEG LI confirms that the updated 2018 cost estimate for the Old Bethpage Substation is $9.7 million, as stated in Exhibit 13, but states that this does not translate into a rate impact of $9.7 million as only the carrying cost of the corresponding debt will ultimately be reflected in rates (PSEG BOE, p. 67).

that each year, it develops an updated, five-year capital budget forecast for LIPA's approval based on the best information available at that time. It contends that before any construction could commence, it and LIPA would need to make a decision to proceed with construction of the proposed substation and LIPA would then need to finance the estimated $9.7 million in construction costs before any effect of the project would be reflected in rates. PSEG LI adds that, under the Public Power Model, there would be no effect on rates if the capital project is not built because it will be reconciled through the DSA in the following year (PSEG BOE, pp. 66-67).

PSEG LI notes DPS Staff's proposal that, if funding for the Old Bethpage Project is needed during the rate period, PSEG LI could re-prioritize its budget in 2018. PSEG LI, however, responds that shifting money within the overall budget, as DPS Staff proposed, would take away funding in existing budgets for other projects needed for reliability, operating efficiencies, or customer services (PSEG BOE, p. 67, citing Tr. 140).

LIPA Staff observes that the DDRR addresses this and other individual capital project budgets by recommending that they “not be approved at this time ...” LIPA Staff states that capital budgeting is a dynamic process, informed by facts and changing circumstances, with one year’s budgets and projects affecting the next, and evolving over time as the projects mature. LIPA Staff says that the 2018 capital budget will be presented to the BOT in late 2017, noting that DPS will have an ongoing role in reviewing capital expenditures as it is obliged to review capital spending annually (LIPA BOE, p. 10, citing PSL §3-b(v)).

In its brief opposing exceptions, DPS Staff expresses its disagreement with PSEG LI's assertion that there is no risk that any construction costs will be collected in rates before PSEG LI and LIPA determine that the project is needed. Saying that it already addressed the issue of risk, and adding that PSEG LI has not provided any new arguments to discredit those assertions, DPS Staff reiterates its support of the DDRR on this issue.

The information presented by PSEG LI and LIPA Staff on exceptions does not persuade us to change the DDRR recommendation because it does not adequately address the basis for recommending the exclusion of such costs in 2018. Since the capital budgets will be updated yearly, based on best available information at that time, it seems there should be sufficient flexibility in the budgeting process to accommodate the financing costs associated with this portion of the project, if construction is actually going to commence in 2018 and if such costs subsequently are confirmed as a necessary component for inclusion in the capital budget in 2018.

Blanket Projects

The DDRR noted that blanket accounts are used to capture and summarize numerous, small routine capital expenditures, such as those for new customer services, street lighting, and repair of minor damage or equipment failures. The DDRR explained that PSEG LI aggregates projects having costs of less than $1,000,000 each into blanket projects; then both specific, individual projects and blanket projects undergo review by the PSEG LI Utility Review Board (URB).

Below, having discovered two projects that were erroneously included under blanket projects, DPS Staff expressed a lack of confidence that less expensive projects are tracked accurately. DPS Staff therefore recommended that the maximum cost of a project to be classified as a blanket project be lowered to $100,000, and that individual projects over $100,000 be identified in a budget summary for the URB. DPS Staff also argued that having a $100,000 limit is consistent with the limit that most other NYS utilities utilize and PSEG LI has not sufficiently demonstrated that it should have a different limit (DPS IB, p. 25; Tr. 576-78).

PSEG LI asserted that it is neither cost effective nor necessary to manage a $100,000 project at the URB level in the same manner as a $1,000,000 project. PSEG LI argued that small routine projects, even though grouped together under a Blanket Category, receive attention and tracking from PSEG LI very similar to that focused on a specific project. It stated that blanket projects are assigned to regional managers and each blanket project is on the work plan to ensure timely engineering and design to complete the project on time. PSEG LI added that each blanket project has its own budget, is tracked and reviewed for variance, and is discussed during work plan and clearance meetings to make sure the necessary labor, material, permits and clearances are available to perform the work. PSEG LI concluded, therefore, that blanket projects are provided all of the supervision and "visibility" that is necessary and appropriate to their scope of work (PSEG IB, p. 63; Tr. 138).

LIPA Staff stated that a threshold level between the $100,000 level advocated by DPS Staff and the $1 million level championed by PSEG LI may better accommodate the needs of all parties. It said that, all else being equal, the capital review group should avail itself of the latest available data and review meaningful projects, rather than routine ones. It concluded that, absent a reason to the contrary, subjecting a subset of lower cost projects to the more formal group review process seems reasonable (LIPA IB, p. 40).

In light of DPS Staff's discovery of two projects that were incorrectly identified as blanket projects (Tr. 589-90) and

PSEG LI's explanation of the extensive review all projects undergo, the DDRR recommended that DPS Staff's proposal to lower the limit for projects that may be included under blanket projects to $100,000 be adopted. It stated that this would be a reasonable and non-burdensome way (as most of the review work is already being undertaken) of helping to make the budget review process more transparent and easier for both PSEG LI and DPS Staff to track and review (DDRR, pp. 78-80).

PSEG LI excepts, instead proposing, as a compromise, a $250,000 limit. DPS Staff opposes PSEG LI's proffered compromise position, asserting that the $100,000 threshold adopted by the DDRR should be maintained. We agree. The limit proposed by DPS Staff and adopted in the DDRR is consistent with the threshold used by other large NYS utilities and no persuasive reasons have been offered for not employing it here.

Multiple Customer Outage Subprogram

Multiple Interruptions is a blanket program consisting of five subprograms aimed at reducing outages on specific circuits or in specific neighborhoods that experience a higher level of interruptions compared to the rest of the system (Tr. 139, 586). As discussed in the DDRR, there was a dispute among the parties regarding the forecast budget for one of the Multiple Interruptions subprograms, the Multiple Customer Outage (MCO) subprogram. Believing the budget for the MCO subprogram to be too high in 2018 relative to historical spending, DPS Staff recommended that the 2018 budget be based on the historic average from 2013-2014, or $5.1 million, a reduction of $2.2 million (Tr. 587).

PSEG LI opposed this reduction. It said that the 2018 MCO funding level increase is completely offset by reduced budgets of $3,090,000 and $4,455,780 for this activity in 2016 and 2017, and that the MCO spending in 2016 and 2017 was below the historical average 2011-2015 spending level of $5,664,000 by a cumulative amount of $3,782,220. According to PSEG LI, the increase in the 2018 MCO subprogram budget is due to shifting dollars from 2016 and 2017, when FEMA funds would be available to strategically reduce mainline outages, to 2018, when the availability of FEMA funds that can be used for this purpose will be winding down (Tr. 138-39). PSEG LI added that shifting budget dollars to 2018 will enable it to surgically address pockets of poor reliability, which will become more apparent as mainline outages are reduced (PSEG IB, p. 64, PSEG RB, pp. 27-28).

For the reasons stated by PSEG LI in its briefs and its testimony on this issue, the DDRR recommended that its proposed MCO budgets be adopted without modification (DDRR, p. 80). There were no exceptions to this recommendation. We recommend adoption of the company’s 2018 MCO subprogram budget.

New Business Accounts

The New Business Accounts program is a blanket projects program in the capital budget that accounts for new customers being added to the system and modifications to the system to enable service installations (Tr. 583). As noted in the DDRR, PSEG LI proposed budgets of $15.49 million in 2016, $15.95 million in 2017, and $16.43 million in 2018 (Exh. 12), while DPS Staff proposed budgets of $13.66 million, $14.07 million, and $14.49 million (DPS IB, p. 24). The DDRR also indicated that, in rebuttal testimony, PSEG LI agreed with DPS Staff’s methodology but disagreed with DPS Staff’s calculation, and instead proposed budgets of $14.66 million, $15.1 million, and 15.55 million in 2016, 2017, and 2018, respectively (Tr. 137), but only DPS Staff briefed this issue.

The DDRR recounted DPS Staff's statement that its adjustment removed abnormal spending in 2013 and abnormal projected spending for 2015. DPS Staff asserted that average spending for 2010-2012 and 2014 is an appropriate budget for the year 2015, and that this amount should then be escalated each year to arrive at the calculations that DPS Staff advocates be used as the proposed budgets for the new business accounts (DPS IB, p. 25). The DDRR found DPS Staff's position to be reasonable, and recommended its adoption (DDRR, p. 81).

Though it did not brief this issue, PSEG LI excepts. DPS Staff opposes PSEG LI's exception. In short, PSEG LI and DPS Staff confirm their continued disagreement as to the correct calculation of the New Business Accounts program budget, with PSEG LI asserting that the budgets are understated and instead should at the levels proposed in its rebuttal testimony ($14.66, $15.1 and $15.55 million in 2016-2018, respectively) (PSEG BOE, p. 69) and DPS Staff asserting that the budgets should be as recommended in the DDRR ($13.66 million, $14.07 million, and 14.49 million in 2016, 2017, and 2018, respectively). However, DPS Staff indicates that its proposed levels are "unloaded" adding that, if the loading factors are ultimately approved, the budgets should be increased accordingly (DPS RBOE, p. 33-34).

Loading factors should be reflected in the new business accounts category. This leads us to agree with the Company's rebuttal testimony amounts of $14.66, $15.1 and $15.55 million in 2016-2018, respectively, which include loading factors.[50]

<u>Substation Control and Protection Improvements</u>

Substation Control and Protection Program is a blanket program consisting of 18 subprograms geared towards improving

[50] The revenue requirement effect associated with this change is *de minimis* in that it only changes LIPA's debt service costs by a small margin. Moreover, debt service costs are fully reconciled.

Substation Control and Protection equipment to reduce the likelihood of equipment failures (Tr. 591). PSEG LI proposed funding of $4.64 million for year 2016, $4.30 million for year 2017, and $10.72 million for year 2018 for this blanket program (Tr. 592). DPS Staff proposed an adjustment of $7 million to this program because it noted that all subprogram costs were within the range of $15,000 to $595,340, except for the Relay Upgrades to Microprocessor Program, which had significantly higher funding ($7 million) in 2018. DPS Staff discovered that the $7 million amount was a placeholder for additional relay upgrades; it further determined that five other Microprocessor Relay Upgrade projects were budgeted for in 2018 under the same project job description as the Relay Upgrades to Microprocessor Program placeholder (Tr. 592-93). DPS Staff therefore proposed to eliminate this placeholder and its recommendation appears to be uncontested (DPS RB, p. 18; Tr. 594).

The DDRR recommended adopting DPS Staff's proposal, which would reduce the Substation Control and Protection Improvements 2018 budget to $3.72 million (DDRR, pp. 81-82).

PSEG LI excepts and DPS Staff opposes PSEG LI's exception. PSEG LI contends that the amounts stated in the DDRR for the Substation Control and Protection Improvements program do not reflect the updated budget amounts set forth in Exhibit 13 (i.e., $5.3 million for 2016; $4.97 million for 2017; and $12.5 million for 2018). Thus, it notes that when DPS Staff's $7 million adjustment for 2018 is reflected, the remainder should be $5.5 million for 2018, including loaders, instead of $3.72 million (PSEG BOE, p. 69).

DPS Staff disagrees with PSEG LI's calculations because it says that PSEG LI's $12.5 million budget includes loading factors but the $7 million adjustment did not. It says that the proper comparison requires that the $7 million adjustment be corrected to reflect the same loader (DPS RBOE, pp. 31-32).

We are persuaded by the Company's explanation in the exceptions process. Therefore, the Department adopts $5.5 million as the correct budget figure for 2018.

Utility Review Board Process

Only PSEG LI briefed this issue below. It noted that DPS Staff, in its testimony, challenged the scope of information that PSEG LI presents to the URB, including data on actual spending to date when a change of funding is requested, and variance reporting (Tr. 574). PSEG LI, however, advocated no changes to the current process. The DDRR accepted PSEG LI's position (DDRR, p. 82).

On exceptions, DPS Staff disagrees with the DDRR's acceptance of PSEG LI's position. DPS Staff asserts that its recommendations would, among other things, "create greater internal awareness of capital projects" and would provide "a useful tool for effective and efficient project management for PSEG LI itself," and should therefore be adopted.

PSEG LI counters that DPS Staff has not specifically identified or articulated its proposed recommendations and has not justified their imposition. PSEG LI adds that, to the extent DPS Staff reasonably requires additional information to carry out its statutory responsibilities, it should make those needs known to PSEG LI outside of this rate proceeding.

The DPS Staff proposal is insufficiently specified and therefore, we recommend adoption of PSEG LI's position, except as otherwise noted above with respect to modifying the threshold limit for inclusion as a blanket project.

AMI

PSEG LI included in its filing a budget of approximately $40.1 million (PSEG IB, p. 112) to expand its Advanced Metering Infrastructure (AMI) program, pointing out that AMI gives customers access to consumption information which enables them to better manage their usage (Tr. 1402). With AMI comes the ability to access PSEG LI's AMI web tool, which allows customers to set budget goals, translates kWh saved into dollars saved and shows environmental impacts. In its experience with the AMI program, PSEG LI reported a two percent decrease in energy consumption for the residential customer group that was offered the web tool and a five percent reduction in energy consumption for the residential customer group that was offered both the web tool and a Time-of-Use (TOU) plan in a limited experiment in the Route 110 Smart Grid Demonstration Project (Tr. 1400). PSEG LI estimated that AMI deployment at the scale it proposed would result in $121 million in labor savings by 2038, as well as improvements in the monthly meter reading rate (Tr. 1391).

PSEG LI's revised proposed AMI program consists of five initiatives: (1) 2015, which includes plans for installation of the AMI communications network infrastructure and 5,139 AMI meters previously proposed for installation in 2015 as part of the Company's Utility 2.0 filing; (2) Phase 1, which includes the deployment of 23,320 AMI meters previously proposed for installation in 2016 and 2017 as part of the Company's Utility 2.0 filing; (3) Phase 2, which includes the deployment of an additional 15,000 AMI meters previously proposed for installation in 2016, 2017, and 2018 on Rate 281 accounts as part of the Company's Utility 2.0 filing; (4) AMI Policy, which includes, in conjunction with Phases 1 and 2, a proposal to deploy an additional 133,920 AMI meters over the period 2016 through 2018 in instances where a conventional meter needs to be replaced or would otherwise be installed; and (5) AMI Saturation, which proposes the incremental deployment of 33,000 AMI meters over the period 2016 through 2018 to fill in the gaps of certain areas to achieve full AMI penetration.

With the exception of the 2015 proposal, DPS Staff opposed the deployment proposed by PSEG LI, finding the proposed roll-out not well defined, inconsistent with existing Commission policies in that it did not require large commercial customers to pay for their AMI meters, and not sufficiently supported by a benefit-cost analysis. Specifically, DPS Staff noted that PSEG LI has based its proposal solely on operational considerations, rather than tying deployment to a means of incentivizing customers to use the information collected by AMI for energy savings. Instead, DPS Staff recommended a limited deployment of meters, beginning with commercial customers with demand of 300 kW or higher, coupled with an alternative rate design called Critical Peak Pricing (CPP). DPS Staff recommended beginning deployment with these larger customers until the Company has gained sufficient experience with the new rate design (Tr. 1509-11). In reply, PSEG LI characterized DPS Staff's CPP proposal as impractical because customers with demand exceeding 300 kW are spread across the territory and, therefore, the proposal would not provide enough meter density to form an adequate "mesh network" to support reliable connectivity. Further, PSEG LI asserted that it has already gained sufficient experience with AMI through multiple pilot programs servicing nearly 8,000 AMI accounts across all customer classes (Tr. 1399).

LIPA Staff expressed general support for the deployment of AMI, but did not advocate for PSEG LI's proposal, stating that any such investments should show a return for customers or other benefits with a sufficiently large margin for error to ensure customers will benefit under a range of assumptions and future conditions (LIPA IB, p. 34-44). LIPA Staff proposed that it continue to work with PSEG LI and DPS Staff to fully develop an AMI implementation plan that would build on the approved initial AMI deployment, address DPS Staff's concerns, and be consistent with the policies being developed in the Commission's REV Proceeding. Such plan, according to LIPA Staff, could be submitted for Department review by the end of 2015 as part of PSEG LI's next Utility 2.0 filing (Tr. 1269).

In its initial brief, SCL asserted that PSEG LI's proposed AMI deployment should be accompanied by plans to provide measurement and verification services that could benefit both the service provider and the end-use customer. SCL recommended that PSEG LI use AMI technology to document the success of energy efficiency and demand-side management programs and as a tool to measure building performance for the purpose of awarding performance incentives for facilities that maintain the operating integrity of ratepayer-funded energy upgrades (SCL IB, p. 11).

In the DDRR, Senior Advisory Staff acknowledged that PSEG LI's AMI proposal is attractive in that it would set the stage for introducing REV programs as they develop, but found that too much uncertainty exists surrounding the role AMI will play in such programs to justify universal deployment of AMI at this juncture (DDRR, pp. 85-86). Accordingly, the DDRR expressed reluctance to recommend that the Board commit LIPA ratepayers to finance the significant investment envisioned in PSEG LI's rate filing. It also stated that it could not be determined on this record whether DPS Staff's proposed alternative proposal -- to limit AMI deployment to commercial customers with demand of 300 kW or higher and to link deployment to a new pricing proposal -- is the most expedient course (DDRR, p. 86). Therefore, the DDRR recommended that both PSEG LI's proposal and DPS Staff's alternative AMI proposal be rejected and DPS Staff's recommended adjustments be adopted.

The DDRR also pointed out, however, that investment in some form of advanced metering will ultimately prove necessary to support greater choice and innovation, such as creative rate design, more ability to manage load factor, creation of customer-facing energy management software, active monitoring of real-time energy data, and the enablement of conservation voltage reduction to capture energy and peak reductions (DDRR pp. 86-87; Tr. 1392).[51] The DDRR recommended that more detail regarding AMI implementation should be included in LIPA's next Utility 2.0 filing or with PSEG LI's IRP to be filed by December 15, 2015 (Tr. 1269), and that actual amounts of AMI investment be updated and reconciled as part of the updates and second stage filing process (DDRR, p. 87).

No party opposes the recommendations related to AMI made in the DDRR, and those that commented provided helpful input to us in forming this recommendation. In its brief on exceptions, PSEG LI expressly states its willingness to pursue approval of its expanded AMI program, "or some variation thereof," as part of the Utility 2.0 or IRP process, noting that the most appropriate cost recovery vehicle for the expanded program would be the update and second stage filing process (PSEG BOE, p. 70). Although PSEG LI believed that the DDRR recommended approval of DPS Staff's alternative program -- with the exception of the CPP proposal -- nothing in PSEG LI's brief on exceptions suggests that its support of the DDRR approach is

[51] See Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), (Framework Order), p. 98.

contingent on the inclusion of DPS Staff's proposed AMI deployment to larger commercial customers. The language employed in the DDRR on this point concededly is unclear on this issue, but we read the DDRR as rejecting DPS Staff's alternative proposal, both the limited deployment of AMI and CPP. In its brief opposing exceptions, DPS Staff states that it interprets the DDRR to recommend rejecting its alternative proposal. Indeed, DPS Staff does not recommend that its alternative proposal, or any AMI program, be adopted without alternative pricing (DPS RBOE, p. 36). In our view, DPS Staff's alternative proposal should be considered at the same time as PSEG LI's updated AMI program proposal.

In its brief on exceptions, SCL reiterates its vision of the potential uses of AMI technology, but ultimately states that it defers to the DDRR recommendation to consider AMI in the context of Utility 2.0 and the IRP (SCL BOE, p. 2). LIPA Staff likewise concurs with the DDRR recommendation (LIPA BOE, p. 10). Finally, DPS Staff agrees with the recommendation that PSEG LI's next Utility 2.0-related filing -- the IRP due December 31, 2015 -- include an AMI proposal. DPS Staff suggests that the PSEG LI filing be revised to include alternate pricing proposals and more closely reflect REV principles (DPS Staff BOE, p. 17). LIPA Staff supports Staff's supplemental suggestions and asserts that PSEG LI analyze cost recovery and rate and service options for customers who may want to "opt out" of AMI (LIPA RBOE, p. 11).

Having fully considered the parties' comments on exceptions, we are satisfied that postponing consideration of a proposed expansion of PSEG LI's AMI program is the most prudent course. We recommend that PSEG LI be encouraged to submit its updated program proposal by the end of this year.[52] Although it seems certain that AMI or some type of Advanced Metering Functionality (AMF) will play a role in enhancing choice and control of the resources that become available under New York's REV policies, much debate still exists over the level, type and necessity of advanced metering.[53] Moreover, PSEG LI's updated program proposal should identify, in addition to anticipated labor cost savings resulting from remote meter reading, major account management, billing and call center operations, other REV-like benefits that can be provided by the program.

DPS Staff, LIPA Staff and PSEG LI should work together to develop a detailed AMI implementation plan to be filed by the end of the year and considered as an update for 2016 rates. Specifically, PSEG LI's next proposal should be supported by a business plan that (1) describes how AMI will advance the Distributed System Platform (DSP), distribution level markets, and REV initiatives; (2) includes, in addition to metering and operational benefits, customer programs with plans for customer engagement; (3) analyzes the impact on billing and other Company systems that may be impacted by the implementation of programs that utilize the increased data AMI provides; (4) provides a description of how AMI and its system can be upgraded and changed to respond to changing needs; (5) is supported by a detailed cost benefit analysis and (6) evaluates the options and feasibility of permitting customers to opt out of AMI.

---

[52] The AMI proposal could be submitted at the same time as the IRP, but as a separate filing. In making this filing, PSEG LI should consider the proposal by the Town Board of Smithtown regarding a time variant pricing pilot.

[53] See Framework Order, pp. 95-97.

Utility 2.0, Energy Efficiency and Renewables

EE Project Cost Analysis (Benefit Cost Analysis)

On December 17, 2014, the LIPA BOT approved a budget for PSEG LI to fund investments in energy efficiency (EE), direct load control demand response, distributed generation, advanced metering and related programs (Utility 2.0 Projects). The Utility 2.0 projects were designed by PSEG LI in accordance with the LRA[54] and to be consistent with the consumer-centric, clean energy, reliability and system-efficiency policies articulated by the Commission in the REV proceeding (Tr. 1262-64).[55] In its filing, PSEG LI proposed to employ the Program Administrator Cost (PAC) test as the primary benefit cost analysis (BCA) test when analyzing whether its energy efficiency and Utility 2.0 program investments are viable alternatives (Tr. 1268).

In its testimony, DPS Staff proposed that, in addition to the PAC test, PSEG LI utilize the Total Resource Cost (TRC) test until a BCA framework is established in the REV proceeding (Tr. 1493). PSEG LI agreed that the TRC test should be calculated and considered, but maintained that the PAC test should be the primary tool for considering cost-effectiveness of the proposed programs because it better emulates the cost/savings decision making that PSEG LI uses in its day-to-day operation of the system. Specifically, PSEG LI pointed out that the TRC test fails to incorporate the impact of rebates and incentives, which can be critical to investment guidance. DPS Staff asserted that adding the TRC test will help align PSEG LI's program evaluations with REV policy (Tr. 1494).

In the REV proceeding on June 1, 2015, DPS Staff submitted a White Paper proposing an initial BCA framework and

[54] PAL §1020-f(ee); PSL §3-b(3)(g).

[55] Case 14-M-0101, Framework Order, pp. 10-13.

seeking feedback for the PSC's consideration before adopting a BCA framework that can be employed by the NYS utilities in implementing REV policies and programs (BCA White Paper).[56] The BCA White Paper proposes that three tests be calculated and applied to evaluate REV programs: the Social Cost Test (SCT), which is essentially the TRC plus the inclusion of certain environmental externalities; the Utility Cost Test (equivalent to the PAC); and the Rate Impact Measure (RIM) test. Although it is premature to rely on the BCA White Paper as a definitive statement as to where the PSC is headed with regard to BCA policy, it is illustrative of DPS Staff's position and indicative of the fact that the PSC will provide guidance as to BCA analysis in the near future.

The DDRR recommended that PSEG LI utilize the TRC in conjunction with the PAC (DDRR, p. 88). No party has raised an exception to this point. We adopt this recommendation as the TRC has been the key metric employed by the PSC in evaluating energy efficiency programs, including its recent application to REV-like programs such as Con Edison's Demand Response and Brooklyn Queens Demand Management Programs,[57] and more completely reflects relevant costs. Until the REV proceeding produces a BCA framework, both the PAC and the TRC should be used to determine whether a program should be employed is advisable and more in line both with the manner in which the PSC has evaluated energy efficiency programs in the past and with DPS Staff's proposal for the future.

---

[56] Case 14-M-0101, supra, Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding (issued July 1, 2015).

[57] Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014), pp. 18-19.

Other Energy Efficiency Issues

PSEG LI identified energy efficiency program expenses amounting to approximately $87.5 million, $89.6 million and $91.8 million for 2016, 2017, and 2018, respectively (Tr. 1480). These annual increases were the result of an annual 2.5 percent escalation rate.[58] In its testimony, DPS Staff asserted that the 2016 base year amount is appropriate, but that the increase in the 2017 and 2018 budgets should reflect the GDP-IPD escalation rate instead of the flat 2.5 percent escalation factor imputed by PSEG LI (Tr. 74). NRDC also proffered some modifications, proposing that PSEG LI achieve a minimum 2 percent annual savings rate for EE and adopt a target specifically focused on scaling up EE in multifamily affordable housing.

The DDRR recommended that PSEG LI's proposed budgets be adopted, with DPS Staff's adjustment (DDRR, p. 90). No party has addressed this recommendation on exceptions, and we adopt the recommendation. The GDP-IPD is routinely employed by the PSC in forecasting cost elements. As a measure of the national economy, it better reflects the commercial climate in which a utility is operating (Tr. 74). But for the adjustment of the escalation factor, however, we otherwise recommend adoption of the proposed budgets. In the REV Framework Order, utilities were directed to maintain existing energy efficiency budgets and targets in 2016 and beyond to avoid market disruption and backsliding while the transition is made to a REV regulatory framework. PSEG LI’s proposed EE budgets are consistent with this interim provision (Tr. 1482). The Framework Order also requires DPS Staff to develop a REV Energy Efficiency Best Practices Guide, with the initial version to be completed by February 1, 2016. Inasmuch as the REV proceeding may result in

[58] These amounts will be offset each year by Regional Greenhouse Gas Initiative (RGGI) funds (Tr. 1480-81).

significant changes to utilities' EE programs in the near future, the changes proposed by NRDC are premature. Instead, PSEG LI should work with Department staff to modify its EE programs as this REV guidance is developed (Tr. 1494).

We also recommend that PSEG LI's EE Rider should be renamed to the Distributed Energy Resources (DER) Rider as proposed by the DDRR, in accordance with DPS Staff's suggestion that it more completely reflect the nature of potential resources and future programmatic shifts under REV (Tr. 1489). This proposal elicited concern from NRDC that EE funds would be used for non-EE purposes (NRDC IB, p. 9) but, nevertheless, was recommended in the DDRR (DDRR, p. 90) and was not addressed on exceptions. We agree with DPS Staff that, given the evolving nature of EE programs under REV, the expansion of the rider name here is necessary to prevent a mischaracterization. The EE Rider is proposed to recover the expenses associated with a direct load control program in addition to energy efficiency expenses, so this name change better reflects the nature of the Rider and thereby provides more transparency to ratepayers (Tr. 1490). As DPS Staff points out, direct load control programs also reduce electric use and electricity production, and thus are consistent with the goals of energy efficiency.

DPS Staff made several other proposals that were not opposed, were included in the DDRR (DDRR, pp. 91-92), were not raised on exceptions, and which we now recommend. The DPS Staff adjustments to the EE Cost Recovery Rider and the proposal that PSEG LI should also report any variances in approved EE budgets and expenditures to Department staff at least quarterly are in accordance with Department policy and are recommended (Tr. 1485). Likewise, DPS Staff and PSEG LI's agreement that EE internal labor costs (and associated benefits) should be recovered in distribution rates, and not in a surcharge such as the EE Rider, with the clarification that contracting costs and other external labor expenses continue to be recovered through the EE rider, should be recognized and adopted (Tr. 1281; 1485). Finally, DPS Staff, LIPA Staff and PSEG LI have agreed to collaborate to address remaining concerns, if any exist, over DPS Staff's proposed adjustments to EE program evaluations and development, capacity figure updates, BCA modification, and demand response programs (Tr. 1282-85).

We find it unnecessary to address NRDC's recommendation that PSEG LI be directed to fully account for Utility 2.0 investments in this rate proceeding. As DPS Staff explains (DPS RB, p. 34), all Utility 2.0 investments have been evaluated and accounted for in this rate proceeding, except for the communications network that is subsumed within 2015 budgetary parameters and therefore is outside the scope of this rate proceeding (Tr. 1499-1500, Tr. 1503).

Distributed Energy Resources

SCL provided a list of criteria to be used to evaluate distributed energy resource (DER) projects proposed within the LIPA service territory (SCL IB, pp. 9-10). Among other factors, SCL suggested that a "standard formula" be developed to calculate a project's net carbon footprint, and that the heat island effect and location of proposed solar and other DER projects be carefully considered. In its brief on exceptions, SCL reiterates its position that utility supported energy efficiency projects would benefit from the implementation of such a measurement and verification protocol (SCL BOE, p. 3). After carefully considering SCL's thoughtful proposal, we cannot recommend adoption of the proposed criteria in this rate proceeding, given the absence of a specific context in which to evaluate their suitability. The proffered evaluation metrics are better considered in proceedings where projects that would invoke their application are being considered. SCL may renew its position with regard to DER projects in future proceedings addressing specific proposed DER projects or in the context of the Company's next Utility 2.0 filing.

Renewables

NRDC recommended that PSEG LI take steps to ensure that 50 percent of its electric demand is supplied by renewable resources by 2025, in accordance with NRDC's broader recommendation that New York State also adopt a 50 percent renewable goal by 2025, as opposed to the 2030 goal set forth in the NY State Energy Plan (Tr. 30-31).[59] In the DDRR, Senior Advisory Staff opined that these arguments are not properly raised in the context of this rate proceeding (DDRR, p. 92). No party addressed this point on exceptions. We recommend that NRDC's arguments in this regard not be resolved in the relatively narrow parameters of this rate proceeding. In a ruling issued March 30, 2015, the ALJs noted that issues related to the sources of generation supply are being addressed separately in LIPA's Integrated Resource Planning process.[60] Finally, the role of renewable resources will continue to be a subject for review in REV and related proceedings. This issue, which is of State-wide importance, should be contemplated in the context of a generic proceeding where the State's goals as a whole may be considered. Accordingly, it is not recommended that NRDC's proposals regarding renewables be addressed by the Board in this proceeding.

---

[59] New York State Energy Planning Board, NY State Energy Plan (issued July 25, 2015) (http://energyplan.ny.gov/Plans/2014.aspx).

[60] Matter No. 15-00262, Ruling on Scope of Issues (issued March 30, 2015).

Rate Design/Cost of Service

As noted in the DDRR, there were no disputes between the parties with respect to the Cost of Service Studies or with PSEG LI's proposals concerning the Commercial Time-of-Use Exit provision, Standby Service or Gross Receipts Tax. In addition, PSEG LI, in its initial brief, stated that the following rate design and tariff changes also were not in dispute:

- Introducing the Delivery Service Adjustment (DSA);
- Removing declining rates for general residential non-space heating customers in the winter;
- Combining and simplifying the residential service rate classes;
- Combining the grandfathered service sub-classes from 1983 with their current corresponding service classes;
- Modifying certain service classes' transfer clauses;
- Increasing the customer and demand charges for Large Commercial Customers (Rate Code 281) by 11 percent per year;
- Changing the Annual Maintenance charge for SC-11 and SC-12 from 11 percent to 8.1 percent;
- Increasing the No-Access Charge from $50 to $100;
- Transferring energy efficiency labor costs from the energy efficiency rider to delivery rates;
- Increasing the Pole Attachment fees for wired and non-wired communication from $9.68 to $11.98 and from $5.00 to $6.19, respectively;
- Introducing the right to charge customers for a second turn off if they tamper with their meter;
- Specifying in the tariff that AMI meter data will be provided for free and that the cost for historical MV90 data will increase from $5.50 to $10;

- Modifying the Excelsior Jobs Program Rate based on the Marginal Cost of Service Study;
- Moving the commercial electric heating rates (Rate Codes 290, 291 and 293) to Rate Code 281; and
- Continuing a Revenue Decoupling Mechanism (RDM).

However, as is also noted in the DDRR, some of the above-mentioned proposals were still contested by SCL and DPS Staff, respectively (DDRR, 93-96).

The DDRR reported that SCL opposed the recently-commenced RDM for failing to include measurement and verification of energy use and demand reductions attributed to Energy Efficiency programs (SCL IB, p. 12). SCL also suggested there be monthly, quarterly or semiannual adjustments to the DSA in order to better align the charge with market prices, and reduce costs associated with delayed recovery of legitimate costs (SCL IB, pp. 13-14). As stated in the DDRR, SCL's arguments for modifying the RDM were unpersuasive and lacking in record support. The DDRR further noted that DPS Staff reviewed the tariffs proposing the RDM, and found that the tariff language was consistent with RDMs recommended by the Department and approved by the Commission for other NYS electric utilities (Tr. 1232-33). SCL excepts, but, since it merely reiterates the same arguments that were previously addressed and rejected in the DDRR, its exceptions are denied and we recommend that the Board retain, without change, its RDM.

Below, SCL also proposed that the DSA be adjusted more frequently than once a year. LIPA Staff responded by arguing that the DSA, which covers debt carrying costs and taxes, among other things, is intended to be reset annually, adding there is no apparent advantage in making it a monthly variable charge. LIPA Staff added that, given the “lumpiness” of debt carrying costs and even property tax payments over the course of the year, monthly calculation of the DSA may well be highly volatile, even if the annual compilation is flat (LIPA RB, p. 5). For the reasons proffered by LIPA Staff, the DDRR agreed that the frequency of resetting the DSA should not be modified. There were no exceptions to this recommendation. Therefore, we recommend that the Board maintain the annual reset of the DSA.

SCL also opposed increasing the Large Commercial Customers (LCC) demand charge (SCL IB, p. 6). As noted in the DDRR, (1) DPS Staff reviewed the originally proposed increase in the LCC demand charge and proposed a lower level of increase that brings the rates into alignment with PSEG LI's cost studies and with the rates of other such customers in the State and (2) SCL's opposition and proposed alternative increase was not based on similar review and lacked any citations to the record. Accordingly, the DDRR recommended that SCL's position not be adopted. There were no exceptions to this recommendation. We recommend that the Board adopt the DDRR recommendation and increase the LCC demand charge as proposed by Department Staff.

DPS Staff opposed PSEG LI's introduction of a new customer service charge that PSEG LI calls a "Removal Charge" and an associated revision to the tariff to provide for the right to recover the cost of customer turn-offs as part of its investigation fees. The DDRR agreed with DPS Staff that the proposed tariff language seems to provide for a charge that would be duplicative and therefore unnecessary. The DDRR therefore recommended that the proposed charge and tariff language not be approved. There were no exceptions to this recommendation. For the reasons stated in the DDRR, we recommend rejection of PSEG LI's proposed "Removal Charge."

<u>Residential and Small Commercial Customer Charge</u>

PSEG LI originally proposed a number of changes to rate design aimed at enhancing customer satisfaction and moving

LIPA's rate design in the direction of other utilities in New York. DPS Staff, however, proposed that implementation of almost all of these changes be deferred, with the issue revisited after the issuance of an order in the REV Track 2 proceeding (Tr. 1211-12).[61] LIPA Staff stated that it fully supports the Commission's efforts in the REV proceeding, and PSEG LI's efforts to more closely align its Utility 2.0 proposal with the Commission's REV initiatives. However, given the three-year period of the Rate Plan filing, LIPA Staff suggested that LIPA, DPS Staff, and PSEG LI consider implementing as many such proposals as are consistent with the rate design of other New York utilities during the current proceeding.

In the DDRR, the Senior Advisory Group observed that Track Two of the Commission's REV proceeding is expected to include a full examination of the current electric utility rate structures and designs (Tr. 1212). As a result, it found that making changes to existing rate design now would be premature. Accordingly, the Senior Advisory Group recommended that the rate structures and designs that are currently in place for residential and small commercial customers not be changed or increased until more guidance is provided as part of the REV Track Two proceeding; and, consistent with this recommendation, the proposals to increase the low-income discount also be postponed as they were intended to offset any proposed increases in the residential customer charge (DDRR, pp. 96-97).

PSEG LI excepts. Citing to the record, PSEG LI observes that LIPA's current residential customer charge of \$10.80 only recovers 39% of the fixed customer-related costs of service of \$27.97 per month, and is lower than the customer charge of any investor-owned electric utility in the state (PSEG

[61] UIU, NRDC, SCL, and SCC also opposed increasing customer fixed charges.

BOE, p. 71, citing Tr. 728-29, 732). PSEG LI states that while it understands the desire expressed in the DDRR to hold the existing rate design in place pending additional guidance from REV Track Two, there are several factors that counsel against that course, including that the REV Track Two matter is still in its early phases and that the customer charges of other utilities are significantly higher than LIPA's (PSEG BOE, pp. 71-72).

PSEG LI argues that the transcript passage upon which the DDRR relies for taking no action at this time was quite vague, both as to the timing of REV Track Two and any effect on customer charges, and that it therefore is an insufficient basis upon which to recommend no change in LIPA's demand charge. Specifically, PSEG LI notes that while the recently-issued Staff White Paper recognizes that the introduction of advanced metering functionality will enable movement beyond the historical dispute between fixed customer charges and volumetric rates, the DDRR did not endorse PSEG LI's AMI proposal (PSEG BOE, p. 72).

Next, after echoing the White Paper's statement that "[a]s part of the proposed transition to a three-part rate (volumetric charge, demand charge, and fixed customer charge), the fixed customer charge should be formulated to reflect only the costs of distribution that do not vary with customer demand or energy consumption," PSEG LI argues that nothing in the record demonstrates that the cost derivation of its proposed customer charge contravenes the White Paper. PSEG LI further argues its proposal is consistent with the Staff White Paper, which reiterates support for fixed customer charges based on cost of service principles. PSEG LI also asserts that the changes it proposed are consistent with the protection of low-income customers expressed by the White Paper (PSEG BOE, pp. 72-73).

PSEG LI argues that the Commission itself has recognized that "[i]mplementation of REV will take years and…[r]ate cases will be decided while this is happening." It adds that the principles that form the basis of REV Track Two reflected in the Staff White Paper are consistent with the current DPS principles identified for setting customer charges. PSEG LI contends that the Staff White Paper, which outlines the Commission's vision for the future, does not provide a compelling reason to refrain from making long-overdue cost-based changes to LIPA's customer charges in this rate matter (PSEG BOE, p. 73).

PSEG LI asserts that when one considers how far below cost-based rates LIPA's current customer charges are, a step toward cost-based rates should be made in this case. It observes that while DPS Staff had pointed to the Order in the recent Central Hudson case as support for its position that the customer charge should be held steady until the REV Track Two case progresses, DPS Staff failed to mention that the current Central Hudson electric customer charge is $24 per month -- almost 2.5 times LIPA's. PSEG LI argues that with or without action in REV Track Two, it stands to reason an increase in LIPA's customer charges will have to be implemented (PSEG BOE, pp. 73-74).

Finally, PSEG LI notes that low usage customers are not necessarily low income customers, adding that the bill impact on a dollar basis is less, not more, for low usage customers under its proposal. PSEG LI also contends that low usage customers have been under-paying their cost to serve for many years, due to the current, unreasonably low customer charge, and that its rate design proposal, in principle, suggests the same rate increase for all customers to increase fairness, better align cost recovery with cost to serve, and make progress toward cost-based rates (PSEG BOE, pp. 74-75).

Noting that LIPA's residential customer charge is, on average, less than half that of the investor-owned utilities in New York, PSEG LI says that its proposal is designed to gradually move LIPA's residential and small commercial customer charges to a level that is approximately 50% of a cost-based charge over a three-year period. It adds that because it is difficult to envision anything coming out of the REV proceeding that would be contrary to its approach, PSEG LI argues that the residential and small commercial customer charges should not be postponed indefinitely but should be implemented as PSEG LI has proposed (PSEG BOE, p. 75).

DPS Staff responds by observing that PSEG LI’s proposed customer charges would increase residential customer charges 83% over the three-year rate period with a 39% increase in the first year alone. DPS Staff takes issue with PSEG LI's statements regarding the alleged impact of its proposal on low income customers, asserting that, even with the increase to the low income discount, the low income customer charge under the PSEG LI proposal would increase by 90% over three years, from $0.18 per day to $0.34 per day. DPS Staff further contends that, under PSEG LI's customer charge proposal, small commercial customers would see customer charges quadruple over the three years from $0.36 per day to $1.44 per day, while small commercial customers who use less than average would experience increases ranging from 25% to 89% under PSEG LI's proposed rates (DPS RBOE, pp. 36-37, citing Tr. 732-733 and 1210 and Exh. 77, p. 3).

DPS Staff asserts that PSEG LI argues for large increases of up to four times current charges to mass market customers over a relatively short period of three years or less, even while acknowledging that the Commission has approved similar changes for other investor owned utilities gradually, over a 30 year time frame (DPS RBOE, p. 37). DPS Staff characterizes PSEG LI's proposal to increase rates over a relatively short time period as being inconsistent with the application of gradualism in setting rates (Id.).

Echoing the same observations noted by PSEG LI in its brief on exceptions, DPS Staff also observes that the REV Track Two White Paper addressed fixed customer charges, called for extensive studies and will not result in the implementation of rate changes "overnight." DPS Staff asserts that, in fairness to ratepayers, such changes should be phased-in. It adds that awaiting the extensive analysis envisioned by the REV Track Two proceeding supports its recommendation for no change in customer charges at this time (Id.).

DPS Staff also argues that PSEG LI assertions regarding the impact of its proposed customer charge increases is misleading, saying that the low use customer who uses 1,400 kWhs per year and pays $264 under current rates would, under PSEG LI's proposal, experience an increase of $113 per year, or 43%. DPS Staff adds that for the "average" customer using 10,000 kWhs per year, PSEG LI proposes a $119 increase on a $1,089 bill, which is an increase of 11% (Exh. 77). Thus, DPS Staff argues, even though the low-use customer “only” received an increase of $113 in comparison to the average customer increase of $119, the low-use bill percent increase is almost 50% greater than a current bill. PSEG LI's proposal, says DPS Staff, provides little protection for its low use customers, who may also be low income customers (DPS RBOE, p. 38).

We are not persuaded to modify the DDRR recommendation. As PSEG LI recognizes in its exceptions, Track

Two of the Commission’s REV proceeding will entail additional study and examination of the current rate structures and designs. While we recognize that such studies will take additional time, it is still premature to recommend increases in the residential and small commercial customer charge before having the benefit of such additional studies and of additional Commission guidance on these important issues. In addition, as DPS Staff notes, the changes proposed by PSEG LI would have significant impacts on residential and small commercial customers. Moreover, the timing of a more definitive and justified plan on AMI should allow for coordination of any implementation of some type of advanced metering technology and a final recommendation in REV on rate design. The marrying of these items should enable customers to address any possible future increase in the customer charge with possible reductions in the variable portion of the bill. Accordingly, we adhere to the recommendation that the rate structures and designs that are currently in place for residential and small commercial customers not be changed or increased until more guidance is provided as part of the REV Track Two proceeding; and, consistent with this recommendation, there should be no modification to the low-income discount.

Phase-out of Grandfathered Residential Water Heating

PSEG LI proposed to eliminate and phase out Residential Electric Water Heating over the three years of the rate plan. DPS Staff agreed, but proposed a five-year phase-out. SCL opposed the elimination of the rate, asserting that those customers who installed electric water heaters were likely influenced by the economics of a preferred electric rate.

As explained in the DDRR, the Senior Advisory Group was persuaded that the continuation of this rate was no longer justifiable, and since it had been grandfathered and closed to new customers since 1983, its elimination was not unreasonable. However, in order to avoid rate shock, be more equitable, and allow customers time to make decisions concerning water heating choices; and, in an effort to be promote consistency among the NYS electric utilities, the Senior Advisory Group determined that the existing customers would be allowed to migrate to time-of-use alternatives over a five-year phase-out period (DDRR, pp. 97-98). There were no exceptions to this recommendation.

Rate Counseling for Rate 285 Customers

SCL recommended that PSEG LI offer counseling to Rate 285 customers to help them ascertain whether they are on the appropriate billing rate, the DDRR requested that PSEG LI respond on exceptions (DDRR, p. 98). PSEG LI responds that it will counsel customers on available rate options, and will assist customers in choosing the service classification that is most appropriate for their current needs, based on the information they provide. It adds that its assistance can include examining the customer's previous usage/load history to project future usage patterns in order to help customers ascertain whether they are on the appropriate billing rate (PSEG RBOE, p. 14).

Online Bill Calculator

The DDRR encouraged LIPA Staff and PSEG LI to respond to SCL's proposal that PSEG LI create an on-line bill calculator that would increase transparency for consumers by allowing them to go on-line to “plug-in” specific billing information from their actual bill to get an informed projection of proposed rate adjustments (DDRR, p. 98). On exceptions, LIPA Staff indicates that PSEG LI is assessing the system capabilities it has and the resources it would need to implement SCL's proposal, while PSEG LI indicates that it will consider the practicality and usefulness of an online bill calculator and report back to LIPA (LIPA BOE, p. 11, PSEG RBOE, p. 15).

Consistent with the Commission's vision in REV, giving customers more information about their energy use is paramount to encouraging customers to be active participants in managing their energy bill. We recommend that LIPA Staff and PSEG LI fully explore this idea and be required to report back to the Board within a definitive period of time.

Customer Billing - NYC

In its initial brief, NYC asserted that LIPA's current systems do not provide monthly billing detail, with each billing determinant, in an electronic format (such as Excel) that may be used for analytical purposes by large customers with multiple accounts. NYC stated that this limited its ability to analyze electricity cost and usage at all of its LIPA facilities over time because it cannot key certain billing parameters, each month, into its own database. It added that even large customers with interval metering cannot monitor consumption and demand on an account and meter level on real- or near real-time basis via a web-based portal. NYC argued that PSEG LI should be required to add such capabilities so that customers would have a powerful tool to take control of and manage their energy usage. NYC further contended that, by adding such capabilities, the Company also would satisfy core objectives of the "Reforming the Energy Vision" initiative and the State Energy Plan.

NYC added that, as a large customer with numerous facilities, energy costs constitute a substantial operating expense. It also stated that decreasing such costs by increasing efficiency aligns with the core policy objectives announced in Mayor de Blasio's *One New York* plan.

Acknowledging that the cost of the upgrades must be considered, NYC recommended that PSEG LI study and file a report with DPS Staff on the capabilities of the current systems, and also address the upgrades and estimated cost needed to provide an online, interactive interface that improves customer access to consumption and demand data on a real-time basis, and, following public comments on the report, DPS Staff advance a recommendation to the BOT as to when these upgrades should be pursued (NYC IB, pp. 26-29).

NYC's requests were inadvertently omitted from the DDRR. Therefore, NYC renewed its requests on exceptions (NYC BOE, pp. 1-2). NYC urges that its concerns be addressed, stating that affirmative action on these requests will provide customers with enhanced opportunities to employ energy efficiency measures and achieve cost savings.

LIPA Staff acknowledges NYC's request that the billing system be enhanced, but states that such enhancements implicate, to some degree, the AMI project. LIPA Staff indicates that it will request that PSEG LI make such billing system enhancements a topic in its next "Utility 2.0" filing (LIPA RBOE, p. 11). LIPA Staff's proposal to have the Company address such billing enhancements as part of the next Utility 2.0 filing is a reasonable and appropriate response that should adequately address NYC's concerns and we recommend adoption of LIPA Staff's offer.

Changing the Winter Demand Ratchet from 70 Percent to 85 Percent

A demand ratchet is a rate mechanism to ensure that customers with widely fluctuating monthly demands adequately contribute to their cost of service. Customers are billed for demand based on the maximum monthly demand they place on the system in the current month or a percentage of their maximum demand in previous eleven months.

PSEG LI recommended that the winter demand ratchet for large commercial customers in Service Classification SC-2L / Rate Code 281 be increased from 70 percent to 85 percent to match the summer demand ratchet (Tr. 785; PSEG IB, pp. 127-28). It indicated the change would produce an increase of 12.95 percent in the number of demand billing units and a corresponding decrease in the per-unit demand rate (Tr. 757-58, 774-75; PSEG IB, p. 128). As the Company illustrated it:

> ... the demand ratchet links a customer's maximum load, which normally occurs in the summer, to the costs that the customer's maximum load imposes on the system (i.e., transmission and transformer costs). The only difference between the current ratchet and PSEG LI's proposed ratchet is that under PSEG LI's proposal, the ratchet value (i.e., 85 percent) is held constant throughout the year. (Tr. 775).

The Company calculated, for example, that the ratchet change would mean that a summer demand of 100 kW will yield a minimum demand charge based on 85 kW instead 70 kW, with the 15kW increase over the customer base in Rate Code 281 producing 12.95 percent more billing units, lowering the demand rate (PSEG IB, p. 128).

The Company asserted that increasing the ratchet would not alter the amount of demand revenues collected from customers; the only change would be to the way demand revenues are collected, by lowering the demand rate and increasing winter billing units (PSEG IB, p. 128). It further stated that the change would not result in a material increase in the annual costs of customers; the impact on customers' individual bills will be minimal (Tr. 758, 774). The benefit of increasing the demand ratchet to 85 percent, PSEG LI said, is that customers' bills would be levelized throughout the year, providing customers with proper price signals to maximize demand usage and allowing them to manage their cash flow more effectively (PSEG

IB, p. 128). It also alleged that the change would better align T&D system costs with customer charges over all months in the year instead of reflecting a greater portion of the costs in customers' summer bills (PSEG RB, p. 58).

DPS Staff, SCC and SCL opposed the Company's recommended increase in the demand ratchet (Tr. 1226-27; DPS RB, p. 36; SCC IB, pp. 5-6; SCL IB, p. 3). DPS Staff argued in its initial brief and again in its reply brief that to increase the demand ratchet, in light of significant increases in the demand charges, would result in an increase in revenues collected from certain customers. Moreover, it argued that development and penetration of distributed resources, such as solar and co-generating units -- a goal of the Commission’s REV proceeding -- may be hindered by an increase in the demand ratchet (DPS IB, p. 59; DPS RB, pp. 39-40).

As noted in the DDRR, the Senior Advisory Group found the record to be insufficiently developed on this issue to recommend supporting PSEG LI's proposal at this time. The DDRR explained that the Company did not point to any exhibits or empirical data in the record to support its claim that the change in the demand ratchet would not result in any material increases in customer annual bills. There was also no empirical data sponsored by DPS Staff to support its claim that increasing the demand ratchet, along with significant increases in demand charges, would result in an increase in revenues collected from certain customers. Moreover, as discussed in other sections of the DDRR, the Senior Advisory Group noted that the REV proceeding is expected to consider a myriad of rate design issues. It concluded that the implications and operations of demand ratchets on REV initiatives would be an appropriate issue to consider under the REV rate design umbrella. And, the Senior Advisory Group agreed with DPS Staff and SCL concerns that the change in the winter demand ratchet might have adverse implications on energy efficiency and REV resource development. Under the present circumstances, the Senior Advisory Group concluded that the winter demand ratchet should not be changed until there is a complete understanding of its implications on revenues and REV planning and resources, and recommended that PSEG LI's proposal to increase the winter demand ratchet should be denied.

PSEG LI asserts on exception to the DDRR that the record is sufficiently developed to support increasing the large commercial customer's winter demand ratchet from 70 percent to 85 percent (PSEG BOE, p. 79). The Company states that it provided detailed bill impacts for large commercial customers demonstrating that the demand revenues would increase by 11% regardless of the implementation of the proposed changes to the demand ratchet and that the bill impacts contained monthly and annual bill calculations for various sized large commercial customers demonstrating the bill impact of the demand ratchet proposal (Id.). It further says a clarifying example was provided showing that increasing billing determinants and lowering the applicable demand rate would not change the total revenues requested for the demand rate component (Id.). Finally, PSEG LI states DPS Staff raised for the first time in initial brief that distributed resources such as solar and co-generating units, considered to be assets under the Commission's REV proceeding, are examples of customers who would be affected by the ratchet (PSEG BOE, p. 80). The Company contends no testimony exists in the record that raises REV, or REV planning, as a reason for rejecting the demand ratchet proposal" (Id.).

Finally, SCL states that it shares the concerns presented in the DDRR over the potential adverse implications from changing the winter demand ratchet (SCL BOE, p. 8).

We find there to be no reason to change the DDRR recommendation. Despite its allegations to the contrary, PSEG LI points to no exhibits or empirical data in the record that we find as sufficient to support changing the winter demand ratchet from 70 percent to 85 percent. It provided no documentation illustrating the impact of the potential change at various usage levels. The Company's focus on a statement of its witness, claiming that the demand ratchet change will have a minimal impact on individual customers' bills, does not rise to the level of what would be considered sufficient evidence in support of such a significant change in the rate design for these customers. Also unavailing is PSEG LI's statement that it provided bill impacts that demonstrate demand revenues would be increased whether or not the demand ratchet is implemented (PSEG BOE, p. 79).

We also do not find persuasive the Company's claim that there is no discussion in the record with respect to the winter demand ratchet and REV. PSEG LI is correct that there is no specific discussion linking REV to the demand ratchet. But, the record is replete with instances of discussion of a host of other rate design issues (e.g. critical peak pricing, standby service, net metering, etc.) in the context of the REV proceeding. The REV program is expected to involve a comprehensive look at rate design and a vast array of rate design issues. Thus, we expect that winter demand ratchets would be considered in the REV proceeding as part of overall rate design. Based on the foregoing, we recommend that the LIPA Board reject PSEG LI’s proposed change to winter demand ratchets.

Residential Electric Space Heating

DPS Staff proposed a gradual phase out of LIPA's residential space heating rate over a five-year period (Tr. 756; DPS IB, p. 54). PSEG LI and SCL disagreed, urging retention of the space heating rates (PSEG IB, pp. 129-31; SCL IB, p. 4). Although not addressing this issue specifically, LIPA Staff stated that PSEG LI and DPS Staff should consider implementation of as many such proposals as would be consistent with the rate design of other NYS utilities (LIPA IB, p. 45). LIPA currently has about 42,000 electric space heating customers.

DPS Staff asserted that eliminating residential space heating rates would make LIPA consistent with all other investor owned utilities in the State, with the exception of Orange and Rockland Utilities, Inc. which is currently phasing out its space heating rates (DPS IB, p. 54). The recommendation to phase out the space heating rates is not based on cost justification, it said, but rather because the Commission has a long standing principle against rates applying only to certain end-use appliances (DPS RB, p. 40). DPS Staff acknowledged that the phase-out will result in higher rates for these customers, and stated that minimizing customer bill impacts is the reason for proposing a phase-out of the rates over five years (DPS RB, p. 41). It noted further that the impact of the increases on electric space heating customers could be mitigated through time-of-use (TOU) rate alternatives, which the Commission supports (Id.).

SCL opposed any reduction or elimination of the space heating rate. It argued that these space heating consumers were likely influenced by the economics of the space heating rate in deciding whether to install all electric space heaters, and that removing the benefit of the lower electric space heating rates will significantly increase the customers' costs through either higher rates they will be charged or through purchasing replacement heating systems (SCL IB, p. 4). SCL asserted that retaining the residential electric space heating rate as the post-REV marketplace develops would serve to boost alternative market technologies, such as heat pump water heaters, that would otherwise be less economic (Id.).

PSEG LI referenced three principal reasons why it opposed elimination of the space heating rate. Specifically, it argued that eliminating the rates would result in significant bill increases for residential customers; costs that far exceed the cost to serve these customers; and, an adverse impact on customer satisfaction (PSEG IB, p. 129).[62] According to PSEG LI, this rate change alone would increase the average monthly winter bill for these customers by about $81 and an overall annual increase of about $262 (Tr. 770; PSEG RB, p. 56).[63] It also pointed out that DPS Staff cited bill impacts as the reason for rejecting Company proposals for eliminating the grandfathered residential water heating rate, increasing customer charges, increasing commercial customer demand charges; and increasing the large commercial customer winter demand ratchet to 85 percent (PSEG IB, p. 130). The Company averred that even with the phase-out of the rates, the DPS Staff proposal would have the highest rate impact on residential customers on a dollar basis (Id.).

The DDRR noted that the existing electric space heating rates, similar to the grandfathered residential water

[62] PSEG LI pointed to a letter from the Leisure Village Board of Directors to support its position that residential space heating customers would be harmed if the DPS Staff recommendation is adopted (PSEG RB, p. 56; Exh. 33).

[63] The Company indicated that the bill impacts were calculated by substituting the proposed DPS Staff delivery rates for residential non-heat customers for current electric space heating rates (Tr. 768-69).

heating rates discussed earlier, only apply to certain end-use appliances, and that differentiating rates on this basis is not recommended. However, as indicated in the DDRR, the Senior Advisory Staff did not find the record in this matter to support recommending a phase-out of those rates over five years as proposed by DPS Staff. The uncontroverted testimony of PSEG LI indicated the elimination of the space heating rates would have a substantial impact on annual customer bills. Although DPS Staff claimed that the economic impact on these customers could be mitigated by moving to TOU rates, there was no analysis provided in the record to show how much of the increase would be mitigated by making such move. The DDRR stated that numerous comments have been received from individuals, including senior citizens, who have expressed much concern over the potential rate increases because they rely on electricity to heat their homes. The DDRR noted that a prediction could not be made as to what, if any, changes in heating appliances would result if the phase-out were to be adopted and there may be a potential for the phase-out to trigger heating appliance changes that might frustrate REV programs and technologies. It further stated that this situation differs from that of residential water heating rates because those rates were closed to new customers decades ago and many customers have already likely begun to convert to more efficient equipment. For those reasons, the Senior Advisory Group recommended that the DPS Staff proposal to phase out the residential electric space heating rates over five years be rejected.

DPS Staff and SCL are the only parties to provide comments on this issue, and SCL's is limited to expressing its agreement with the outcome stated in the DDRR. DPS Staff contends that the DDRR conclusion, to retain the electric space heating rate, is inconsistent with its recognition of LIPA

Staff's support for implementation of rate design provisions consistent with those of other New York State utilities and the Commission's long-standing principle against declining block rates and rates applying only to certain end-use appliances (DPS BOE, p. 18). It questions that, notwithstanding those considerations, the DDRR concluded electric space heating service should not be eliminated at this time, in part, because of the substantial impact on annual customer bills (Id.). DPS Staff recounts that it recognized the rate impact issue and proposed the gradual elimination of the space heating rate to mitigate the impact, and that it believes the potential adverse rate impact that would result from implementing its recommendation can be mitigated through TOU rate designs (DPS BOE, PP. 18-19). Staff claims that the five year phasing out of the rate classification spares customers from the immediate impacts (DPS BOE, p. 19). However, DPS Staff again admits that it performed no analysis to show what the impact of a change to TOU rates would have (Id.).

We see no basis to change the recommendation in the DDRR. DPS Staff has not offered evidence to support its statement that the rate impacts associated with elimination of the residential electric space heating rate will not be as severe as the Company claims. Moreover, with postponement of the deployment of AMI, as discussed above, residential customers affected by the elimination of this rate may not have the tools necessary to be responsive to the new higher rate. We, therefore, recommend that the LIPA BOT retain the residential electric space heating rate.

Recalculation of the Cost-Based Seasonal Rate Differential

PSEG LI initially proposed to eliminate the seasonal differential non-heat residential service classes and the winter/summer seasonal differential for the energy and demand rates charged to commercial customers (PSEG IB, p. 125). The Company recommended, without further explanation, that a new or updated cost-based seasonal differential be applied by service class to set winter/summer seasonal rates (Id.). LIPA Staff did not comment specifically on the seasonal rate differential but supported consideration being given to implementing as many rate design proposals during this proceeding as are consistent with the rate design of other in-state utilities (LIPA IB, p. 45). DPS Staff, UIU and the SCL supported retention of the seasonal rates (Tr. 1224; DPS IB, pp. 56-58; UIU IB, p. 3; SCL IB, p. 3).

PSEG LI stated that eliminating the seasonal differences in rates would assist in presenting a simple and understandable flat rate (Tr. 730; PSEG IB, p. 125). It argued that seasonal rates are not cost-justified and there is no need to have rates higher in summer when customers are already overburdened by their high utility bills because of usage (Tr. 757, 773-74). Moreover, LIPA offers balanced billing, it said, which eliminates the price signal to conserve energy associated with higher rates in summer months (Id.). In addition, seasonal differentials have changed significantly as a result of changes in the generation capacity costs and summer billing units since 1991, the last time that seasonal rates were last cost-justified (PSEG IB, p. 126).[64] Not only have the energy costs been removed from delivery rates, stated PSEG LI, but summer billing determinants have increased due to increased use of air conditioning, particularly central air conditioning (Id.).

The Company claimed that the T&D system costs do not vary season by season even if system loads change month-to month

[64] The Company indicated that the seasonal rates were last set in Cases 29484 and 88-E-084, Long Island Lighting Company – Electric Rates, Opinion and Order Approving Settlement Agreement (issued November 18, 1988).

(PSEG IB, p. 127). Moreover, it asserted that delivery rates collect delivery costs which do not materially vary by seasons (PSEG RB, p. 56). PSEG LI acknowledged that certain power supply costs in LIPA's delivery rates have a seasonal aspect and would be appropriate for recovery on a seasonally differentiated basis (Tr. 776). Generation costs are seasonal, it said, based on the premise that a generator choosing to build a baseload or peaker unit must consider tradeoffs between capacity and energy costs (PSEG IB, p. 127). The Company explained that its witness calculated and presented seasonal rate differentials based on the remaining generation capacity costs still in delivery rates, and the calculation should be used in setting seasonal rates, rather than adopting the DPS Staff proposal which maintains the differential based on an outdated study (Id.). PSEG LI concluded that removing seasonality from rates for LIPA's commercial customers would reduce their high summer bills and help these customers better manage cash flows (Tr. 786).

DPS Staff emphasized that LIPA's T&D system is constructed to ensure that it complies with design criteria to meet projected summer peak demand (Tr. 1207). It argued that the PSEG LI approach would ignore a key factor in facility T&D design and construction, that the costs for facilities constructed as a result of summer peak load should be recovered in summer prices (DPS RB, p. 38). According to DPS Staff, summer peak is considered by the NYISO in setting installed capacity (ICAP) requirements; recognized in PSEG LI's load research studies that show system coincident and non-coincident peak occurring in summer months; and is a major consideration by PSEG LI's design and planning engineers in the T&D system design and construction for LIPA (DPS RB, p. 39).

DPS Staff said that, due to the additional capacity needed to meet peak demand, the LIPA system has one of the lowest load factors of all the NYS electric utilities (44 percent), which clearly evidences the fact that the LIPA system is not efficient (DPS RB, pp. 38-39). LIPA is a summer peaking utility, DPS Staff insisted, whose electric facilities are stressed by increased air conditioning loads in response to high summer temperatures and an influx of summer visitors (Id.). It concluded that adopting PSEG-LI's proposal would have the adverse effect of encouraging peak load growth (Tr. 1222).

DPS Staff noted that the Company's position on the seasonal rate differential issue changed somewhat in rebuttal testimony, to recognize seasonal differentials for generation capacity put into service prior to 1998, the costs of which are included in delivery charges. And, it stated that other generation capacity costs added since 1998 are included in the fuel and purchased power cost adjustment (FPPCA), recovered over the course of the year as a fixed monthly charge with no seasonal adjustment (DPS RB, p. 38).

Regarding the Company's claim that removing seasonality from rates would reduce high summer bills and assist commercial customers' management of cash flow, DPS Staff stated that the FPPCA is typically five to seven cents per kWh higher in winter than summer from the use of natural gas for generation (DPS RB, p. 39). Factoring in the higher summer/lower winter delivery rates with the lower summer/higher winter monthly fuel charges should assist in meeting the PSEG-LI goal of helping commercial customers manage cash flows, declared DPS Staff (Id.).

The DDRR explained that seasonal rates are designed to further two important regulatory goals, to promote conservation and to align rates to the extent practicable with the cost drivers. For LIPA, summer peak load is a primary factor in T&D facilities design and construction. The DDRR pointed out that the PSEG LI's claim that there is no need to have higher rates in summer when customers are already overburdened by their high utility bills because of usage failed to consider that many LIPA customers also use natural gas service for heating and that during summer months their gas usage and bills for service are much lower than during winter months. As the DDRR pointed out, of the more than 7,000 public comments received in opposition to the proposed rate increase, over 2,000 highlighted that they are electric heating customers. Those customers, in particular, the Senior Advisory Group found, would be affected by the seasonal differential.

The DDRR acknowledged that LIPA offers a balanced billing option, but it rejected PSEG LI's claim that the billing option eliminates the price signals associated with higher summertime delivery rates (Tr. 774). It explained that customers on a balanced billing plan still receive a bill that reflects charges at the higher seasonal rate during the summer, and continue to receive the appropriate price signal and incentive to conserve electricity.

As indicated in the DDRR, the Senior Advisory Group also did not find the Company's claim that seasonal rates would help LIPA's commercial customers better manage cash flows to be a compelling basis to adopt its proposed change. The DDRR noted that, aside from PSEG LI's assertion, there was no evidence presented in the record to suggest that commercial customers are experiencing difficulties managing their cash flows as a result of the current rate structure. It stated, moreover, that without the showing the existing filed rate is presumed to be just and reasonable.

The DDRR explained that overall rate design is an integral component of the ongoing REV proceeding.[65] It pointed out, as indicated in a recently issued Department whitepaper, that broad rate design considerations are contemplated to "encourage desired market and policy outcomes including energy efficiency and peak load reduction, improved grid resilience and flexibility, and reduced environmental impacts in a technology neutral manner."[66] Further, seasonal rates are clearly related to the broad rate design policy considerations and could be directly or indirectly affected by REV rate design changes. And, DPS Staff indicated that REV Track 2 is expected to include a full examination of current rate structures and designs (Tr. 1212). The DDRR, therefore, concluded it is reasonable to avoid making changes in the existing seasonal rates for LIPA in the interim. As a result, the DDRR recommended that the PSEG LI proposal regarding seasonal rates be rejected and that the recommendation of DPS Staff, UIU and SCL, to maintain the existing seasonal rate structure, be adopted for the term of the three-year rate plan.

PSEG LI excepts to the DDRR recommendations and SCL comments, simply stating that it agrees with the DDRR recommendation to maintain the existing seasonal rate structure. PSEG LI claims that, although it understands the impetus for the recommendation in the DDRR for no changes to be made in the seasonal rates, the recommendation is unwarranted (PSEG BOE, p. 76). The Company states that it is extremely concerned about the customer impact of failing to address the seasonal rate problem, arguing that the DDRR determination will result in the

---

[65] Case 14-M-0101, supra, Order Instituting Proceeding (issued April 25, 2014), Attachment 1 and Memorandum and Resolution on Demonstration Projects (issued December 12, 2014).

[66] Case 14-M-0101, supra, Staff White Paper on Ratemaking and Utility Business Models (July 28, 2015), p. 95.

rate request being allocated mostly to customers' summer electric bills, whereas PSEG LI's recommendation would allocate the rate request to non-summer months to increase fairness and help customers avoid the rate shock of high summer bills (PSEG BOE, p. 77). The Company also says such high bills "will engender significant customer dissatisfaction and compromises PSEG LI's mission to change the perception of LIPA and the value of the service delivered." (Id.). In addition, PSEG LI points out that the DDRR, responding to concerns of electric heating customers who are affected by seasonal rates, accepted the Company's recommendation to maintain the existing rate discount for electric space heating despite DPS Staff's objections (PSEG BOE, pp. 77-78). According to the Company, the retention of the space heating rate discount mitigates the impact on those customers (Id.).

The Company has not presented any new information or arguments in brief that would persuade us to revise the recommendation of the DDRR. All of the claims made by PSEG LI were considerations that were taken in account already in the DDRR. Using this rate design to mask the impact of a rate increase is not a valid reason to eliminate seasonal rates. Sending the right price signal, one keyed to the nature of the system (e.g., its peak periods) is important, especially when REV rate design and determinations regarding AMI will be made in the near term. Accordingly, we recommend that the LIPA BOT reject PSEG LI's exceptions to the DDRR's recommendation.

Low-Income Program Outreach

As discussed in the DDRR, one of the low-income programs offered in the LIPA service territory is the Household Assistance Rate (HAR) program. The HAR program provides a 50 percent daily discount from the Customer Service Charge of $0.36 per day for both heating and non-heating low-income residential customers. Customers automatically qualify for the HAR program if they have received a benefit from the Home Energy Assistance Program (HEAP); Medicaid; Food Stamps; Temporary Assistance for Needy Families or Safety Net Assistance; Supplemental Security Income; Veterans Administration Veteran's Disability Assistance or Veteran's Surviving Spouse Pension; or Child Health Plus Health Insurance Program (Tr. 631-32).

The HEAP program had an enrollment of 61,475 low-income customers in 2015 in Nassau and Suffolk Counties, while HAR had an average enrollment of 15,300 low-income customers in 2014 (Tr. 635). Additionally, the HAR program has a cap of 50,000 customers (Tr. 632). Accordingly, DPS Staff recommended that PSEG LI adjust its HAR outreach efforts and programs to mirror the HEAP enrollment results (Tr. 635-37).[67] DPS Staff, joined by the UIU, proposed that PSEG LI partner with the New York State Office of Temporary Disability Assistance (OTDA), the Department of Social Services, and other relevant agencies, such as the Nassau and Suffolk Department of Social Services, to reach HAR-eligible low-income households and boost HAR enrollments (Tr. 636). DPS Staff, joined by the UIU, also proposed the removal of the 50,000 customer cap on eligible customer participation under the HAR program (Tr. 636-37).

PSEG LI agreed with removing the HAR enrollment cap (see Exh. 35 (JTT-12, Schedule 1, Revised Leaf No. 188; PSEG RB, p. 46). PSEG LI also agreed with DPS Staff's recommendation to increase enrollment and participation in its HAR Program, but

[67] In its testimony, DPS Staff recommended that PSEG LI reallocate part of its outreach funding to promote the HAR program (Tr. 636); UIU joined in this recommendation (UIU IB, p. 4) but was the only party to address it in brief. PSEG LI and DPS Staff should address this recommendation in their briefs on exception and, at a minimum, state whether the recommendation is still a contested issue and identify the amount of funding that is proposed to be reallocated.

stated that it has hit barriers in increasing participation in the HAR income rate discount program due to an inability to receive HEAP customer information to provide for automatic enrollments into the HAR program (Tr. 1386-87). It noted having reached out to OTDA for a database of such customers so it can match them to its customer database, but said that the OTDA was unable to provide this information due to privacy issues.

The DDRR recommended that PSEG LI and DPS Staff work with OTDA and social services agencies to address the privacy issues that are impeding efforts to automatically enroll HEAP participants into the HAR program. It suggested that parties look to examples from other NYS utilities, notably Con Edison, on how to develop seamless coordination between HEAP enrollment and HAR enrollment. Noting the importance of this program and its relatively low likelihood of a significant over-subscription, the DDRR found it reasonable to remove the program cap at this juncture. The DDRR indicated that any program expenses that exceed the program rate allowance can be recovered through the RDM.

Moreover, the DDRR noted that the low income program for PSEG LI may be informed by the outcome of the current Energy Affordability Proceeding pending at the PSC.[68] It mentioned AARP's recommendation for an increase in the discount provided by HAR, utilizing the methodology proposed in the Staff white paper recently submitted in that proceeding,[69] but, with the Affordability Proceeding still underway, the DDRR found that adopting AARP's recommendation would be premature. The DDRR stated that PSEG LI should, however, revise its program for rate

[68] Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Consumers, Order Instituting Proceeding (issued January 9, 2015) (Affordability Proceeding).

[69] Case 14-M-0565, supra, Staff Report (June 1, 2015).

year 2017 to reflect the best practices adopted by the PSC at the conclusion of the Affordability Proceeding (DDRR, pp. 109-111). On exceptions, PSEG LI indicates it will review the final decision in the Affordability Proceeding and confer with LIPA to determine to what extent the recommendations should be implemented by PSEG LI (PSEG BOE, p. 81).

Given the importance of ensuring low income ratepayers are treated equitably when it comes to discount programs, a key driver behind the Affordability Proceeding, we recommend that the LIPA BOT direct PSEG LI to provide it a report as to the outcome of the proceeding and how LIPA's low income program can be modified accordingly.

Other Issues

Performance Ratios

Below, Nassau County argued that PSEG LI failed to provide common industry performance ratios and demonstrate purported management results and efficiencies in its rebuttal testimony (Nassau IB, p. 10). PSEG LI responded that Nassau County improperly referred to and relied on extra-record materials in its brief, and adds that, in any event, the performance ratios, metrics or benchmarks in the functional areas (operational performance; customer service; metering, billing and collection; financial performance and competitiveness; or operational cost control) referred to at page 11 of Nassau County's brief are all part of the OSA performance metrics (PSEG RB, pp. 61-62). PSEG LI stated that its testimony on these matters was filed on January 30, 2015 and the panels discussing these issues included the Metrics and Safety Panel, the Customer Services Budget and Operations Panel, and the T&D Budget and Operations Panel. It adds that Nassau County had only to review this information and ask any discovery related to it if it wanted information (Id.).

The DDRR found that the County's assertions were misplaced and did not provide sufficient or persuasive bases to recommend denial of the proposed rate increase in its entirety (DDRR, pp. 111-112). There were no exceptions and, therefore, the LIPA BOT need not address this issue.

Request for NYS OSC Review

The DDRR responded to a request by the Town of Brookhaven (Brookhaven or Town) that the DPS or the ALJ Panel invite the NYS Comptroller and the Office of the State Comptroller (OSC) to independently review and provide a binding recommendation regarding the proposed three-year rate plan. It observed that Brookhaven made a similar request in an application it filed on May 14, 2015, in this matter, to which LIPA Staff responded. In the DDRR, Brookhaven's request that an invitation be extended to OSC from either the DPS, generally, or the ALJ Panel, specifically, was denied. The DDRR found it would not be appropriate for the DPS to invite OSC to conduct such a review or to delegate binding approval authority to OSC.

As stated in the DDRR, the DPS is authorized to (1) review rate proposals submitted to it by LIPA (and its service provider, PSEG LI) and (2) provide its recommendations on the proposed rates to the LIPA BOT.[70] The new rates will be set by

[70] PAL §1020-f(u)(1)states that LIPA and its service provider "shall, on or before February first, two thousand fifteen, submit for review to the department of public service a three-year rate proposal for rates and charges to take effect on or after January first, two thousand sixteen (emphasis supplied)" while PAL §1020-f(u)(4) states that "[a]ny recommendations associated with a rate proposal submitted pursuant to paragraphs one and two of this subdivision shall be provided by the department of public service to the board of the authority immediately upon their finalization by the department."

LIPA, not the DPS.[71] LIPA Staff noted that there is nothing in the LRA that contemplates OSC rate review or authorizes the DPS or LIPA to request OSC review.

Brookhaven cited to several cases in an effort to support its position that, pursuant to N.Y. Constitution Article V §1 (pertaining to a subdivision of the state) and Article X §5 (pertaining to a public corporation) and pursuant to PAL §1020-w, OSC "has full authority to 'supervise' the 'accounts' of LIPA, which includes review, approval, or disapproval of LIPA's proposed rate increases" (Brookhaven IB, p. 10). The DDRR determined that Brookhaven's case citations, however, did not support its position. Instead, the DDRR noted that the cases establish that where a public authority or corporation has invited OSC review, it has been expressly authorized to do so pursuant to statute.

Brookhaven offered only one case where a public corporation invited OSC review. In Worth Const. Co., Inc. v. Hevesi,[72] the NYS Thruway Authority requested OSC's review (of contracts, not rates) but did so pursuant to a statutory provision that expressly provided, in pertinent part, that "[a]t the request of the [Thruway] authority, ... all other state officers, departments, boards, divisions and commissions shall render services within their respective functions."[73] Because no

[71] PAL §1020-f(u)(4) requires that, absent a preliminary determination that any particular recommendation is inconsistent with the authority's sound fiscal operating practices, any existing contractual or operating obligations, or the provision of safe and adequate service, LIPA's board shall implement such recommendations, or, in the event that the LIPA board makes such a preliminary determination, it shall provide for additional procedural steps prior to making its final rate determination.

[72] 8 N.Y.3d 548 (2007).

[73] PAL §362.

such similar statutory provision authorizing the DPS or LIPA to make such a request had been identified by Brookhaven here, the DDRR concluded that it would not be appropriate for the DPS to extend the invitation.

Moreover, the DDRR observed that none of the cases cited by Brookhaven hold that OSC supervision over "accounts" includes OSC review and approval of “rates” and that Brookhaven conceded that, in Patterson v. Carey,[74] the Court of Appeals "assumed" but did not decide that OSC's supervisory power was broad enough to encompass the approval of Thruway (toll) rate increases. Thus, the DDRR was unwilling to accept that dicta as a basis to conclude that OSC review would be permitted in the instant matter. In fact, it noted that, in the Lawson decision that was also cited by Brookhaven, OSC refused to examine a proposed Thruway toll increase, indicating that under the Patterson case, any proposed toll increase by a public corporation like the Thruway Authority was not dependent upon OSC review and support.[75] The DDRR concluded that the lack of any cited precedent for OSC to conduct the binding review Brookhaven requests further supported the decision not to issue the invitation.

[74] 41 N.Y.2d 714 (1977). In both Patterson and Lawson v. NYS Thruway Authority (77 N.Y. 2d 86 (1990), the Court invalidated legislation that would have required OSC to review proposed toll increases, holding that such statutes constituted impermissible interference by the Legislature with OSC's discretion to supervise accounts.

[75] Brookhaven cites two other cases, Sgaglione v. Levitt, 37 N.Y.2d 507 (1975), and McCall v. Barrios-Paoli, 93 N.Y.2d 99 (1999), but they do not involve OSC's review of rates. In fact, in the McCall case, there is extensive discussion of the broad scope of OSC’s authority to conduct an audit of city agencies, yet notably, there is no mention of reviewing rates set by any city agencies.

The DDRR also noted that: the OSC had the ability to review the proposed three-year rate plan from the time the plan was filed with the Department in late January; the Commission's rules for party intervention, which were relied upon for this case, are extremely broad; and, given the general purpose of the OSC, it could easily have obtained party status. With party status, it observed that the OSC could have obtained the right to access confidential and non-confidential material, propound its own discovery on LIPA and PSEG LI, offer expert witness opinions, participate in cross-examination of Company and Authority witnesses, and advocate its position through the filing of trial briefs. The DDRR further observed that the OSC did not at any time request party status (DDRR, pp. 112-115).

Brookhaven takes exception, asserting that " ... at issue is LIPA's 'contract' with PSEG." (Brookhaven BOE, p. 6). Brookhaven also asserts that "rates charged to customers are themselves 'contracts'" and that the case upon which it almost exclusively relies (<u>Worth Const. Co., Inc. v. Hevesi</u>[76]) "<u>did</u> involve a rate case" (<u>Id</u>.). PSEG LI asserts that Brookhaven's legal analysis is "flawed" and has no basis (PSEG RBOE, p. 17). We concur.

The DDRR already responded to Brookhaven's previous attempts to rely on the <u>Worth</u> case and that previous discussion discloses the inaccuracy of its now-modified characterization of that case (DDRR, pp. 113-114). With respect to Brookhaven's assertion that rates are contracts, the cases relied upon by Brookhaven previously were reviewed and were found to provide no support for Brookhaven's view (DDRR, pp. 114-115). Finally, we assume that the "contract" that Brookhaven now claims is "here at issue" is the OSA that was executed between PSEG LI and LIPA some time ago. Approval of the OSA also occurred quite some

---

[76] 8 N.Y.3d 548 (2007).

time ago and is not "at issue" in this rate matter. Moreover, the LRA specifically exempted the modified OSA from Comptroller review.[77] Thus, for the reasons articulated here and in the DDRR, Brookhaven's exceptions are denied.

CONCLUSION

As stated in the DDRR, the Department’s goal is to endeavor to craft recommendations that result in proposed rates that are at "the lowest level consistent with sound fiscal operating practices ... and which provide for safe and adequate service" and will protect Long Island ratepayers to the maximum extent possible, consistent with the LRA and OSA. We have considered all the parties' exceptions to the DDRR. Where there were no exceptions, the DDRR’s recommendations should be affirmed. Where there were exceptions, we have indicated whether we were persuaded by them to reverse the DDRR’s recommendations.

Based on our consideration of the exceptions, together with the entire record in this proceeding, we conclude that rates should be based on revenue requirements that increase by $30.4 million in 2016, $77.6 million in 2017 and $79.0 million in 2018, as reflected in Appendix I. As noted, the LRA was designed to address considerable deficiencies in the provision of electric service on Long Island that materialized during Sandy. While no one likes prices increases, it is critical that service on Long Island remain reliable and secure. Long Island’s economy, just like that of any other community, depends upon the presence of efficient, reliable and secure electricity. This means that rates must be set at a level that provides the

[77] LRA §13 (providing exclusive means for amendment of the OSA “notwithstanding section 112 of the state finance law,” which would require OSC approval).

revenues necessary to achieve these goals, but at the same time we remain mindful of Long Island consumers' interests in not paying more than necessary to obtain this value. For the reasons stated herein, we believe that the ratemaking process has produced a result that allows the Trustees to accept our recommendations with the confidence that the objectives of the LRA and the interests of Long Island electric consumers are met.

APPENDIX I
Schedule 1 of 5

Long Island Power Authority and Subsidiaries
Matter 15-00262
Revenue Requirements per Department Recommendation
For the Rate Year Ending December 31, 2016
(000's)

	Rebuttal As Adjusted by PSEGLI	Reclassify Public Power Adjustments	Initial & Reply Briefs Additional Adjustments	Final As Adjusted by PSEGLI	Adj No.	Adjustments per Department Recommendation	As Adjusted per Department Recommendation	Revenue Increase/ (Decrease)	Rate Year After Increase
Total Revenues	$ 3,703,382	$ (17,922)		$ 3,685,460	(1)	$ 12,494	$ 3,697,954	$ 30,395	$ 3,728,349
Fuel and Purchased Power Costs	1,681,830			1,681,830			1,681,830		1,681,830
Revenue Net of Fuel Costs	2,021,552	(17,922)		2,003,630		12,494	2,016,124	30,395	2,046,519
PSEG Long Island Operating Expenses	496,306			496,306	(2)	(15,546)	480,761		480,761
PSEG Long Island Managed Expenses	587,159			587,159	(3)	(190)	586,969		586,969
Utility Depreciation	0			-			0		-
PILOTs - Revenue-Based Taxes	38,043		(505)	37,538	(1)	128	37,666	312	37,978
PILOTs - Property-Based Taxes	304,015			304,015			304,015		304,015
LIPA Operating Expenses	83,802			83,802			83,802		83,802
LIPA Depreciation and Amortization	0			-			0		-
Swap, LOC, and Remarketing Fees	39,728		1,404	41,132			41,132		41,132
Total Expenses	1,549,052	0	899	1,549,951		(15,608)	1,534,344	312	1,534,656
Other Income and Deductions	32,297	17,922	0	50,219			50,219		50,219
Grant Income	38,363			38,363			38,363		38,363
Excess of Revenues Over Expenses	543,160	-	(899)	542,261		28,102	570,362	30,083	600,445
LIPA Debt Service	279,256		(1,151)	278,105	(4)	(15)	278,090		278,090
UDSA Debt Service	204,148		0	204,148			204,148		204,148
Fixed Obligation Coverage Requirement @ 20%	119,727		(1,516)	118,211	(4)	(3)	118,208		118,208
Revenue Surplus/(Shortfall)	**$ (59,971)**	**$ -**	**$ 1,768**	**$ (58,203)**		**$ 28,120**	**$ (30,083)**	**$ 30,083**	**$ -**

APPENDIX I
Schedule 2 of 5

Long Island Power Authority and Subsidiaries
Matter 15-00262
Revenue Requirements per Department Recommendation
For the Rate Year Ending December 31, 2017
(000's)

	Rebuttal As Adjusted by PSEGLI	Reclassify Public Power Adjustments	Initial & Reply Briefs Additional Adjustments	Final As Adjusted by PSEGLI	Adj No.	Adjustments per Department Recommendation	Add Allowable Rate Increases	As Adjusted per Department Recommendation	Revenue Increase/ (Decrease)	Rate Year After Increase
Total Revenues	$ 3,719,491	$ (19,917)	$ -	$ 3,699,574	(1)	$ 5,319	$ 30,395	$ 3,735,288	$ 77,622	$ 3,812,910
Fuel and Purchased Power Costs	1,701,494			1,701,494				1,701,494		1,701,494
Revenue Net of Fuel Costs	2,017,997	(19,917)	0	1,998,080		5,319	30,395	2,033,794	77,622	2,111,416
PSEG Long Island Operating Expenses	517,101			517,101	(2)	(17,092)		500,009		500,009
PSEG Long Island Managed Expenses	582,874			582,874	(3)	(360)		582,514		582,514
Utility Depreciation	0			0				0		-
PILOTs - Revenue-Based Taxes	37,889		(535)	37,354	(1)	54		37,408	789	38,197
PILOTs - Property-Based Taxes	310,250			310,250				310,250		310,250
LIPA Operating Expenses	85,225			85,225				85,225		85,225
LIPA Depreciation and Amortization	0			0				0		-
Swap, LOC, and Remarketing Fees	29,177		11,861	41,038			0	41,038		41,038
Total Expenses	1,562,516	0	11,326	1,573,842		(17,398)	0	1,556,444	789	1,557,233
Other Income and Deductions	33,928	19,917	0	53,844		0	0	53,844		53,844
Grant Income	38,363			38,363				38,363		38,363
Excess of Revenues Over Expenses	527,771	-	(11,326)	516,445		22,717	30,395	569,557	76,832	646,390
LIPA Debt Service	226,968		(3,495)	223,473	(4)	(384)		223,089		223,089
UDSA Debt Service	265,614		0	265,614				265,614		265,614
Fixed Obligation Coverage Requirement @ 30%	158,963		(1,161)	157,802	(4)	(115)		157,686		157,686
Revenue Surplus/(Shortfall)	**$ (123,773)**	**$ -**	**$ (6,670)**	**$ (130,443)**		**$ 23,216**	**$ 30,395**	**$ (76,832)**	**$ 76,832**	**$ -**

APPENDIX I
Schedule 3 of 5

Long Island Power Authority and Subsidiaries
Matter 15-00262
Revenue Requirements per Department Recommendation
For the Rate Year Ending December 31, 2018
(000's)

	Rebuttal As Adjusted by PSEGLI	Reclassify Public Power Adjustments	Initial & Reply Briefs Additional Adjustments	Final As Adjusted by PSEGLI	Adj No.	Adjustments per Department Recommendation	Add Allowable Rate Increases	As Adjusted per Department Recommendation	Revenue Increase/ (Decrease)	Rate Year After Increase
Total Revenues	$ 3,726,435	$ (22,160)	$ -	$ 3,704,275	(1)	$ 1,020	$ 108,017	$ 3,813,312	$ 78,970	$ 3,892,281
Fuel and Purchased Power Costs	1,714,252			1,714,252				1,714,252		1,714,252
Revenue Net of Fuel Costs	2,012,183	(22,160)	0	1,990,023		1,020	108,017	2,099,060	78,970	2,178,029
PSEG Long Island Operating Expenses	523,962			523,962	(2)	(9,182)		514,780		514,780
PSEG Long Island Managed Expenses	581,506			581,506	(3)	(538)		580,968		580,968
Utility Depreciation	0			-				0		0
PILOTs - Revenue-Based Taxes	39,300		(2,071)	37,229	(1)	10		37,240	799	38,039
PILOTs - Property-Based Taxes	316,613			316,613				316,613		316,613
LIPA Operating Expenses	87,353			87,353				87,353		87,353
LIPA Depreciation and Amortization	0			-				0		0
Swap, LOC, and Remarketing Fees	26,117		14,917	41,034				41,034		41,034
Total Expenses	1,574,852	0	12,846	1,587,698		(9,710)	0	1,577,988	799	1,578,787
Other Income and Deductions	35,087	22,160	0	57,247				57,247		57,247
Grant Income	38,363			38,363				38,363		38,363
Excess of Revenues Over Expenses	510,781	-	(12,846)	497,935		10,730	108,017	616,682	78,170	694,852
LIPA Debt Service	210,098		(3,801)	206,297	(4)	(1,170)		205,127		205,127
UDSA Debt Service	296,740		0	296,740				296,740		296,740
Fixed Obligation Coverage Requirement @ 40%	195,127		(1,673)	193,454	(4)	(468)		192,986		192,986
Revenue Surplus/(Shortfall)	**$ (191,184)**	**$ -**	**$ (7,372)**	**$ (198,556)**		**$ 12,369**	**$ 108,017**	**$ (78,170)**	**$ 78,170**	**$ -**

Long Island Power Authority and Subsidiaries
Matter 15-00262
Revenue Requirement Summary per Department Recommendation
For the Rate Years Ending December 31, 2016 through 2018
(000's)

Explanation	Incremental Totals 2016	2017	2018	Total
LIPA/PSEG LI Incremental Rate Request (current position)	**$ 58,204**	**$ 72,239**	**$ 68,113**	**$ 198,556**
LIPA/PSEG LI Cumulative Rate Request (current position)	**$ 58,204**	**$ 130,443**	**$ 198,556**	**$ 387,203**
Prior Year Increases		**(30,396)**	**(108,017)**	**(138,412)**
Add Revenue Taxes to LIPA/PSEG LI rate request	**603**	**1,028**	**926**	**2,557**
Adjusted LIPA/PSEG LI Rate Request	**$ 58,807**	**$ 101,075**	**$ 91,465**	**$ 251,348**
Revenues				
To adopt DPS' sales forecast increase	(12,494)	(5,319)	(1,020)	(18,834)
PSEG LI Operating Expenses				
To adopt DPS' reduction of Customer Service outreach expenses	(1,495)	(1,495)	(1,495)	(4,486)
To adopt DPS' reduction of contractor costs related to REV	(909)	(909)	(909)	(2,728)
To adopt DPS' reduction in distribution circuit trimming & removal costs to reflect a trim cycle starting in 2016	(9,788)	(9,746)	-	(19,535)
To reduce budget for pole inspections in accordance with Draft Recommendation	(1,061)	(1,061)	(1,061)	(3,182)
To adopt DPS' adjustment for the bulk power definition impact	(455)	(455)	(455)	(1,364)
Inflation adjustment to benefits expense	(308)	(666)	(1,042)	(2,016)
Inflation adjustment to Shared Services non-labor expenses	(634)	(472)	(505)	(1,611)
Inflation adjustment to Energy Efficiency total budget	-	(306)	(607)	(913)
Inflation adjustment to Power Markets non-labor expenses	(131)	(161)	(187)	(480)
Inflation adjustment to Customer Services non-labor expenses	(190)	(317)	(426)	(932)
Inflation adjustment to T&D non-labor expenses	(533)	(1,141)	(1,700)	(3,374)
Escalation adjustment for wages included in PSEG LI's Operating Expenses	(202)	(538)	(890)	(1,631)
Total PSEG LI Operating Expenses	(15,707)	(17,267)	(9,276)	(42,250)
PSEG LI Managed Expenses				
Escalation adjustment for wages included in PSEG LI's Managed Expenses	(192)	(364)	(543)	(1,100)
Debt Service and Coverage				
To adjust debt service to recognize capital budget reductions of $ 16.263m in 2016, $17.873m in 2017, and $36.023m in 2018	(19)	(504)	(1,656)	(2,178)
Total Recommended Adjustments	(28,412)	(23,454)	(12,496)	(64,362)
Revenue Requirement per Department Recommendation	**$ 30,396**	**$ 77,621**	**$ 78,969**	**$ 186,986**
Cumulative Revenues per Department Recommendation	$ 30,396	$ 108,017	$ 186,986	$ 325,398

NOTE: The above adjustments include the effect of revenue taxes

APPENDIX I
Schedule 5 of 5

Long Island Power Authority and Subsidiaries
Matter 15-00262
Summary of Department Recommendation Adjustments
For the Rate Years Ending December 31, 2016 through 2018
(000's)

Adj. #	Explanation	2016	2017	2018	Total
1	**Revenues**				
	To adopt DPS' sales forecast increase	$ (12,366)	$ (5,265)	$ (1,010)	$ (18,641)
2	**PSEG LI Operating Expenses**				
a.	To adopt DPS' reduction of Customer Service outreach expenses	(1,480)	(1,480)	(1,480)	(4,440)
b.	To adopt DPS' reduction of contractor costs related to REV	(900)	(900)	(900)	(2,700)
c.	To adopt DPS' reduction in distribution circuit trimming & removal costs to reflect a trim cycle starting in 2016	(9,688)	(9,647)	-	(19,335)
d.	To reduce budget for pole inspections in accordance with Draft Recommendation	(1,050)	(1,050)	(1,050)	(3,150)
e.	To adopt DPS' adjustment for the bulk power definition impact	(450)	(450)	(450)	(1,350)
f.	Inflation adjustment to benefits expense	(304)	(659)	(1,031)	(1,995)
g.	Inflation adjustment to Shared Services non-labor expenses	(628)	(467)	(500)	(1,594)
h.	Inflation adjustment to Energy Efficiency total budget	-	(303)	(601)	(904)
i.	Inflation adjustment to Power Markets non-labor expenses	(130)	(160)	(186)	(475)
j.	Inflation adjustment to Customer Services non-labor expenses	(188)	(314)	(421)	(923)
k.	Inflation adjustment to T&D non-labor expenses	(528)	(1,129)	(1,683)	(3,340)
l.	Escalation adjustment for wages included in PSEG LI's Operating Expenses	(200)	(533)	(881)	(1,614)
	Total PSEG LI Operating Expenses	(15,546)	(17,092)	(9,182)	(41,820)
3	**PSEG LI Managed Expenses**				
	Escalation adjustment for wages included in PSEG LI's Managed Expenses	(190)	(360)	(538)	(1,088)
4	**Debt Service and Coverage**				
	To adjust debt service to recognize capital budget reductions of $ 16.263m in 2016, $17.873m in 2017, and $36.023m in 2018	(18)	(499)	(1,639)	(2,156)
	Total Recommended Adjustments	**$ (28,120)**	**$ (23,216)**	**$ (12,369)**	**$ (63,705)**

Note: Above adjustments do not include effect of revenue taxes.

Staged Updates and DSA Reconciliations

This Appendix establishes the bases for (1) the staged updates (Fall 2015 update, the 2016 "second-stage" update, and the 2017 "third-stage" update); and (2) the Delivery Service Adjustment ("DSA") reconciliation. The three staged updates are forward-looking, while the three DSA reconciliations are backward-looking.

The table below shows the specific items subject to staged updates and DSA reconciliation. The list is the same for all years, except with regard to the Collective Bargaining Agreement ("CBA"), which is scheduled for completion in November 2016, and which will result in an adjustment in 2017 and 2018 to base rates to reflect the terms of the negotiation. The staged updates are completed before the annual period begins, based on known and measurable changes, and the DSA adjustments are calculated after the annual period for that rate year. The annual period for the DSA reconciliations is defined as October through September of each year. The timing is shown below.

Review Performed	Staged Updates to Base Rates	Delivery Service Adjustment	Bill Impacted with Usage starting
Oct/Nov 2015	Rate Case Update for 2016 – 2018	----	1/1/2016
Oct/Nov 2016	Second Stage Update for 2017 and 2018	Reconcile 9 months ending Sept 2016	1/1/2017
Oct/Nov 2017	Third Stage Update for 2018	Reconcile 12 months ending Sept 2017	1/1/2018
Oct/Nov 2018	----	Reconcile 12 months ending Sept 2018	1/1/2019

Overview of Updates, Staged Filings, and Delivery Service Adjustment Calculations

Step in the Process	Approximate Date	Items Covered	Update or Second Stage Adjustment	Delivery Service Adjustment (DSA)
2015 Update for known changes in costs since Department recommendation	Oct/Nov 2015	• Current interest rates • 2015 UDSA refinancing • PSA pension/OPEB settlement • PSA property tax settlement • T&D property PILOTs 2015 actual expense times 2015 known percentage increase over 2014 • Other legal or regulatory mandates	Update Delivery Service Rates for 2016. Rates to be effective in 2017 and 2018 may also be approved at this time.	
2016 DSA Calculation	Oct/Nov 2016	• Debt Service, other interest earnings and expense • Storm Cost Reserve (including storm preparation) • PSA/NMP Expense		Calculate DSA based on 2016 actuals (through September) to be reflected in 2017 bills
2016 "Second-Stage" update for known changes	Oct/Nov 2016	• 2016 CBA and associated costs for changes in the level of benefits and payroll related overhead costs (e.g., payroll taxes) • Current interest rates • 2016 CapX financing • 2016 UDSA refinancing • PSA pension/OPEB settlement • PSA property tax settlement • T&D property PILOTs 2016 actual expense times 2016 known percentage increase over 2015 • Other legal or regulatory mandates	Update Delivery Service Rates for 2017. Rates to be effective in 2018 may also be approved at this time.	
2017 DSA Calculation	Oct/Nov 2017	• Debt Service, other interest earnings and expense • Storm Cost Reserve (including storm preparation) • PSA/NMP Expense		Calculate DSA based on 2017 actuals (through September) to be reflected in 2018 bills
2017 "Third-Stage" update for known changes	Oct/Nov 2017	• 2016 CBA and associated costs for changes in the level of benefits and payroll related overhead costs (e.g., payroll taxes) • Current interest rates • 2017 CapX financing • 2017 UDSA refinancing (if happens) • PSA pension/OPEB settlement • PSA property tax settlement • T&D property PILOTs 2017 actual expense times 2017 known percentage increase over 2016 • Other legal or regulatory mandates	Update Delivery Service Rates for 2018. Approved rates will remain in effect until changed by the Trustees in a subsequent action.	
2018 DSA Calculation	Oct/Nov 2018	• Debt Service, other interest earnings and expense • Storm Cost Reserve (including storm preparation) • PSA/NMP Expense		Calculate DSA based on 2018 actuals (through September) to be reflected in 2019 bills