

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.

NOTICE OF PROCESS FOR FILING EXCEPTIONS

(Issued August 21, 2015)

Attached is a Draft Department Rate Recommendation in the above-referenced matter. Although this document differs from a Recommended Decision in several procedural aspects, the Department intends to follow Public Service Commission Rule 4.10 by analogy, and invites briefs on exceptions and briefs opposing exceptions. The parties' exceptions briefs should therefore adhere to the requirements of 16 NYCRR §4.10(c).

Briefs on exceptions are due to be filed with the Secretary and served on all parties by 4:30 p.m. on Thursday, September 3, 2015. Briefs opposing exceptions are to be filed and served by 4:30 p.m. on Friday, September 11, 2015.

PSEG LI is directed to include, as an appendix to its brief on exceptions, tables showing the bill impact, for each service classification, by rate year, of the rate changes proposed in the attached Draft Recommendation. PSEG LI should consult with Department Staff as necessary in preparing this appendix.

(SIGNED)

KATHLEEN H. BURGESS
Secretary

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DRAFT DEPARTMENT RATE RECOMMENDATION

(August 21, 2015)

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INTRODUCTION

On January 30, 2015, in accordance with Public Service Law (PSL) §3-b and Public Authorities Law (PAL) §1020-f, PSEG Long Island, LLC (PSEG LI or the Company) and the Long Island Power Authority (LIPA or the Authority) submitted a three-year rate plan (2016 through 2018) for review by the Department of Public Service (DPS or the Department). PSEG LI and LIPA 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 revenue requirement increase of \$441 million. At these proposed levels, LIPA's overall electric revenues, including power supply costs, would increase by 2.0 percent each year. Looking solely at the impact on delivery revenues, the increases for 2016, 2017 and 2018, would be 3.9 percent, 4.0 percent, and 4.0 percent, respectively.

Throughout the proceeding, PSEG LI, LIPA, DPS Staff, and other parties proposed and updated revenue requirement positions. The culmination of this activity and the corresponding record lead to this draft recommendation that PSEG LI and LIPA set rates designed to increase revenues by \$28.786 million in 2016, \$78.493 million in 2017, and \$81.267 million in 2018.¹ These rates represent a cumulative revenue requirement

¹ Appendix I to this draft recommendation is a schedule reflecting the revenue requirement effect of our proposed resolution of all contested issues.

increase of \$324.611 million, a reduction of approximately 26 percent from the original revenue increase request.

The filing is unique in several respects. To start, it is the first rate filing by LIPA since PSL §3-b was enacted. Second, it is not presented based on a cost-of-service model and a historic test year, but rather was prepared using prospective budget information, as required by the December 31, 2013 Amended and Restated Operating Services Agreement (OSA) that exists between LIPA and PSEG LI. Third, the budgets were prepared by a new service provider, PSEG LI, operating under a new business model and operational plan that had been implemented on January 1, 2014. Fourth, pursuant to statute, the Department is required to review the rate proposal and make its recommendation to the Board of Trustees (BOT) for LIPA within 240 days, or by September 27, 2015.²

BACKGROUND

DPS Staff immediately commenced its review of the rate filing, and other interested individuals, corporations, organizations, state agencies, and municipalities intervened as parties. DPS Staff and other parties engaged in extensive discovery, and, ultimately, LIPA and PSEG LI responded to over 600 information requests.³ Administrative Law Judges (ALJs) were assigned to conduct the public statement and evidentiary hearings, rule on requests for party status, establish the procedural schedule and facilitate the orderly processing of this matter.

² 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.

³ Many of the information requests propounded by the parties were multi-part.

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, 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. 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, 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 1500 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; the City of New York; the Suffolk County Comptroller (SCC); Natural Resources Defense Council; the Utility Intervention Unit, Division of Consumer Protection, NYS Department of State (UIU); the Town of Brookhaven; and a late submission, filed by the

Suffolk County Legislature (SCL).⁴ Post-hearing reply briefs were filed by LIPA; PSEG LI; DPS Staff; the City of New York; and the Town of Brookhaven.⁵

As we noted above, this filing is the first one to be submitted by LIPA and its service provider, PSEG LI, since the enactment of PSL §3-b. Just one year before the rate filing, PSEG LI embarked upon the management and operation of the Long Island electric system. 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, PSEG LI assumed operational and policymaking responsibilities that are more expansive than those of its predecessor. The recent transition to a new provider and new business model often meant that historical information was not readily available or accessible. The rate filing also reflects the fact that LIPA, unlike an investor owned utility (IOU), is a public power authority that is financed using debt instruments and has no stockholders.

The applicable statute expressly states that the purpose of the Department's review is "to make recommendations 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

⁴ 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.

⁵ 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. SCL's brief has been accepted for filing.

operating practices."⁶ It 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."⁷ These standards govern our review of the arguments and positions that have been articulated by the parties on this record.

With regard to PSEG LI's obligations in the context of this rate filing, we observe that, in several instances, PSEG LI asserts that certain adjustments to its proposed expense budgets are foreclosed by the OSA and the LIPA Reform Act (LRA) (e.g., PSEG IB, pp. 6-9, 82-86, 99-104). We disagree. The LIPA Reform Act requires DPS to "review and make recommendations to the Board of Trustees (BOT) of LIPA with respect to the rates and charges," recommendations that are designed to be consistent with ensuring that the revenue requirements related to such rate review are sufficient to satisfy LIPA's obligations "with respect to its bonds, notes and all other contracts." PSL §3-b(3)(a). The OSA is one of those "other contracts." As such, while our recommendations must not contravene that contract, we must properly rely on our expertise and judgment in assessing the weight of the evidence that has been presented to us in order to formulate and present the Department's recommendations to the LIPA BOT concerning the appropriate level of LIPA's rates and charges.

⁶ PSL §3-b(3)(a)(i).

⁷ PSL §3-b(3)(a)(ii-iii).

In assessing such evidence, we will not be persuaded by assertions that any and all forecasted expenditures must be accepted "as is" simply because they may pertain to the OSA. To the contrary, we observe that 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*" (emphasis supplied).⁸ Therefore, PSEG LI must provide sufficient record support for information concerning its portions of the rate plan proposal. In addition, the ability of PSEG LI to recover expenditures associated with the management and operation of the system does not trump the underlying statutory requirement that rates be set at "the lowest level consistent with sound fiscal operating practices...and which provide for safe and adequate service." While PSEG LI is entitled to recover its costs and receive a reasonable opportunity to achieve performance metrics, that right is not limitless, but rather must be applied under the overarching statutory mandate of the LIPA BOT. Consequently, we will assess whether there is sufficient record support to recommend that the proposed rates are at "the lowest level consistent with sound fiscal operating practices ... and which provide for safe and adequate service." In doing so, we have strived to protect Long Island ratepayers to the maximum extent possible, consistent with the need to afford statutorily mandated compensation to LIPA and PSEG LI to provide the requisite electric service.

Nassau asserts that PSEG LI "failed to sustain its burden of proof" with respect to the requested rates. Brookhaven argues that DPS Staff failed to present a complete record in opposition to PSEG LI's rate increase and that the

⁸ OSA, §6.1(E)(1)(b)(i)(emphasis added).

hearing record does not support the rate increase. We disagree. As noted above, the process followed here included the extensive exchange of information both in the form of hundreds of written discovery questions and numerous exchanges of technical information, including the formal technical conference held during March of 2015, and phone calls between and among various parties and their expert witnesses. It culminated in two days of evidentiary hearings producing a hearing record that exceeds 1,500 pages of transcript and contains over 130 exhibits. We find that this process has resulted in a record that is sufficiently robust that it allows the Department to meet its obligation to make recommendations to the LIPA BOT as required by the LRA.

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 2015.⁹ 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

⁹ The public statement hearings were held in Riverhead on March 2nd, Smithtown on March 3rd and Rockaway Park and Mineola on March 4th.

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.¹⁰ 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.¹¹

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.¹²

¹⁰ The Department's Document and Matter Management System indicates a lower total number of comments received, because several comments filed in this matter had hundreds of comments by other individuals attached. We have counted each individual's comment in arriving at this higher figure.

¹¹ A few individuals question how customer bill charges are calculated and raise concerns over the customers' ability to understand their bills.

¹² The AARP form letter allowed Long Island residents to simply fill in their names and addresses for submission to the Commission. A section in the letter also allowed the residents to add personal messages.

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.¹³ 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

¹³ Leisure Village consists of 1,500 condominiums. Leisure Knoll comprises about 700 homes and Leisure Glen about 650 homes.

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 charges 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.

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.¹⁴ 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

¹⁴ The summary here is not a complete description of the AARP document. However, AARP's document was fully reviewed and considered in arriving at this draft recommendation.

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.¹⁵

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.¹⁶ 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.¹⁷ 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

¹⁵ AARP referenced an appendix (Appendix 1) which was not included with its filing.

¹⁶ AARP says that the DPS Staff-supported revenue requirement reductions to the rate filing are simply the starting point.

¹⁷ Case 14-M-0565, Energy Affordability for Low Income Utility Customers, Staff Report (issued June 1, 2015).

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.¹⁸

CONTESTED ISSUES

Procedural Matters

Before we turn to the substantive contested issues, we address Nassau County's procedural arguments. Nassau County asserts that (1) PSEG LI did not timely respond to its discovery requests and (2) Nassau County should have been granted an adjournment of one week to prepare its cross examination. We note that 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. Nassau's lack of compliance with the ALJs' instructions for handling discovery and preparations for the hearing in this case

¹⁸ We have not addressed comments that raise issues outside the scope of this rate proceeding.

is fully documented on the record of the hearing (Tr. 947-54). Although the ALJs denied Nassau's requests to cross examine a witness for which it had previously waived its right of cross examination and to adjourn the hearing for a week, they made efforts to provide Nassau with alternative means for making its case (Tr. 5, 947-54). In renewing its complaints in its brief, Nassau uses the word "prejudice," but it does not actually explain how it has been prejudiced in this case. It makes no 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. We therefore find its procedural complaints to be without merit.¹⁹

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

¹⁹ Nassau County also asserts that PSEG LI did not contact the County as promised. 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. We note, however, that good communication between PSEG LI and the County is important and we encourage PSEG LI to take all steps necessary to facilitate such communication.

(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.²⁰

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 employees 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 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 capital real personal income, CDD, and heat degree days (HDD) and including a leap year adjustment variable

²⁰ The Other Sales forecast accounts for 3 percent of the total sales forecast (Tr. 306, 393).

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 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 argues that DPS Staff's total forecast, generally, and C&I sales forecast, in particular, are unrealistically high and overly optimistic. PSEG LI asserts 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 states 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 argues that such technical disputes about econometric models ultimately must give way to real world results. It notes 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 says it updated its forecast for corrections identified by PSEG LI with respect to the commercial and industrial sales data (Exh. 140, p. 6). It argues 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 adds 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 explains that failure to pass the autocorrelation test calls into question the reliability of the Company's forecasts. DPS Staff further explains 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 states that its model includes key economic variables such as electricity price, CDD, and real GMP for Long Island (Tr. 374-76). Finally, DPS Staff argues 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).

We recommend adoption of the DPS Staff's sales and customer numbers forecasts. We note that a Revenue Decoupling Mechanism (RDM) was approved by the LIPA BOT in the Spring; the RDM will address and account for the differences between forecast and actual sales.

Residential Sales

DPS Staff's residential model and forecast is being recommended because it uses 10-year CDD and HDD inputs. The Company's model did not include HDD as an input and it used 30-year average of annual CDD (Tr. 308-09). 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. This method also is consistent with recent Commission decisions concerning sales forecasts.²¹

C&I Sales

We recommend DPS Staff's C&I model because 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). Moreover, the Company does not explain why its models sometimes lack a weather variable and/or a price variable.

We also have some concerns with respect to the level of out-of model adjustments that were made by PSEG LI to account for DSM. 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. Since 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

²¹ See, e.g. Case 10-E-0362, Orange and Rockland Utilities, Inc. - Rates, Order Establishing Rates for Electric Service (issued June 17, 2011), p. 11.

electricity usage, and DPS Staff's DSM adjustments are more reflective of that fact, we find the DSM adjustment methodology employed by DPS Staff to be more reasonable and appropriate than that employed by PSEG LI. We also note and approve of DPS Staff's decision to reflect PSEG LI's cogeneration adjustments as proposed (Tr. 392-93).

Finally, we are not persuaded by PSEG LI's accuracy/MAPE argument. DPS Staff addresses why the MAPE comparison to EIA was inapposite and unreasonably impacted by the PSEG calibration process (DPS RB, p. 8). DPS Staff explains that neither the EIA nor NYISO forecasts for Long Island use a calibration process that is comparable to the process PSEG LI uses. DPS Staff adds that EIA and NYISO forecasts are long term energy forecasts, whereas the PSEG LI forecast is a short term forecast. DPS Staff also observes 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, we are not inclined to rely on the asserted accuracy of PSEG LI's forecasts as a basis for their adoption.

Other Sales

As noted above, DPS Staff accepted PSEG LI's other sales forecast as a starting point, then updated it to reflect 2014 actual sales. This resulted in a delta of 4,985 MWh (0.8 percent) each rate year (Tr. 335, 393). We recommend DPS Staff's forecast because it more appropriately reflects and accounts for actual data and experience.

Customer Numbers²²

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). 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 n 2016, 2017, and 2018, respectively (Tr. 377). These rates are not contested in brief, and the variance between them is less than 0.1 percent (Tr. 377-79). We recommend adoption of DPS Staff's forecast of customer numbers.

Debt Financing

There are three principal issues related to LIPA Staff's financing plans: LIPA's 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.²³ 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,

²² The differences in the forecasts of customer growth are *de minimis* and it is not clear whether they are in dispute.

²³ 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.

replacements and capital additions, the principal of and interest on any obligations ... as the same severally become due and payable.”²⁴ Further, LIPA must establish or maintain any reserves or other funds or accounts required by the terms of its debt covenants.²⁵

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 maintains that the higher degree of investor confidence, the lower its borrowing costs will be (Id.).

PSL §3-b provides that the DPS 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.”

DPS Staff reviewed the proposal to use the PPM to determine the revenue requirement in this case. DPS Staff concluded the PPM met two general principles (Tr. 270). First,

²⁴ PAL §1020-k(6).

²⁵ Id.

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 concludes the PPM should lead to financial results that 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, we recommend use of the PPM for the determination of LIPA revenue requirements.

There are three major components of LIPA's debt service requirements included in the revenue requirement model: LIPA 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 agree: 1) to using current interest rates to estimate debt service requirements for LIPA's debt (DPS IB, p. 11),²⁶ 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). We have reviewed the record and all of the evidence presented and find 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

²⁶ 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.

ensure customers pay actual cost incurred for debt payments and an appropriate level of related coverage.²⁷

Regarding the debt service coverage ratios, LIPA Staff proposes to phase in increased coverage ratios over the three rate years (Tr. 261; LIPA IB, p. 22). LIPA Staff's goal is to improve LIPA 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 agrees 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. Including UDSA, the targeted debt coverage ratios in the respective rate years are 1.10x, 1.15x and 1.20x, respectively (Tr. 261; DPS IB, p. 11). There is no opposition to the proposed coverage targets by any other parties. We support the proposed debt service ratios as a reasonable approach to improving the financial position of LIPA and increasing its access to lending sources over time.

There is 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 proposed rate plan. LIPA Staff notes 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

²⁷ 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.

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).²⁸ 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 notes 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).

LIPA Staff supports 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.²⁹ Any variations resulting from financings in subsequent periods LIPA proposes to be reconciled through the DSA (LIPA IB, pp. 23-24).

DPS Staff opposes the shifting of UDSA refinancing debt cost savings beyond the term of the rate plan, preferring that the savings be reconciled during the term of the plan (DPS

²⁸ The refinancing may involve up to 180 individual bonds and result in about 50 new UDSA bond maturities (Tr. 244).

²⁹ The 2015 savings were previously proposed for reconciliation as part of the second stage filing (LIPA IB, p. 23).

IB, pp. 11-13). According to DPS Staff, shifting 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).

It is clear that 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 to \$192 million, with the most current estimates ranging from LIPA Staff's \$172 million to DPS Staff's \$192 million. All parties agree that the full value of the resulting savings should be credited to LIPA's customers in rates or the DSA. The issue that remains in contest here is the appropriate value to include in revenue requirement as an estimate to which actual costs will be reconciled.

LIPA Staff has 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). These goals seem reasonable and appropriate. Accordingly, we recommend accepting LIPA Staff's savings estimate, subject to update when the results of the first tranche of refinancing are known later this year. Additionally, we support the full reconciliation of debt service costs to ensure that LIPA's customers bear no more or less than the actual debt costs in rates.

Operation and Maintenance Expenses

Vegetation Management Expense

Distribution Tree Trimming Program

PSEG LI proposes 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, recommends that the 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. In January of 2014, PSEG LI initiated tree trimming 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).³⁰ The parties agree that a four-year trim cycle represents an industry best practice and should be employed. The expanded trim box size comports with 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.

³⁰ The extended box provides greater clearance between the trees and wires (Tr. 1111).

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 proposes to complete trimming the remaining 60 percent of the system by 2017, to complete the four-year cycle, and it argues that funding levels of \$27.4 million for 2016 and 2017 are therefore necessary (PSEG RB, p. 9). The Company indicates 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. By 2018, it notes, the distribution lines would already have been aggressively trimmed, large diameter tree branches would have been removed and a larger amount of vegetation debris would have been removed, resulting in trimming cost savings per year in the new cycle (Tr. 1006).

In contrast, DPS Staff proposes that PSEG-LI continue to trim 20 percent of its distribution system per year for the three years of the rate plan, and thereafter begin a four-year cycle, trimming 25 percent per year. This position contributes to Staff's reduced annual tree trimming cost.

We recommend the DPS schedule, because there has been no demonstration here that the ratepayer impact of the more costly accelerated program is justified by a need to address reliability or customer service concerns. We acknowledge 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). The Company, however, 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 tends to

undermine its claim of reliability and customer satisfaction concerns, and its alleged need to accelerate the trimming cycle to complete it in two years.

We reject PSEG LI's claim that adopting DPS Staff's schedule for completing the expanded trim box will result in roughly 50,000 additional vegetation related outages (Tr. 1005, 1090). PSEG LI's characterization of the projection as very conservative does not diminish our concerns that it is based on a number of unsupported assumptions and is too speculative for us to rely upon it (Tr. 1090). 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 points out that reliability on Long Island is high (LIPA IB, p. 38). The Company agrees that it has been providing excellent reliability and points out that it has been meeting the performance metrics in the OSA (Tr. 984). It also states that it will continue to identify and prioritize circuits that need to be trimmed earlier in the cycle (Tr. 1004). Under these circumstances, we do not see a need to accelerate distribution tree trimming so that the first program cycle is completed by the end of 2017. Our recommendation is that the revenue requirement adopted by the LIPA BOT be based on completing the expanded trim box in 2018.

The Company's \$9,600 cost per mile of distribution to be trimmed in 2016 and 2017 is based on competitive bid estimates that it has received; the reduced unit cost of approximately \$7,900 for 2018 reflects savings that would be realized because PSEG LI would be starting a new trim cycle after the system is trimmed to the expanded box in 2017 (Tr. 1006; PSEG IB, p. 12). DPS Staff supports the use of the 2018

projected cost of \$17.75 million for all three rate years, during which PSEG LI would trim 20 percent of its distribution system per year. Notwithstanding its suggestions both in testimony and in briefs that PSEG LI's cost per mile is too high, DPS Staff's proposal actually results in a cost per mile approximately equivalent to PSEG's \$9,600 unit cost plus 4 percent adder for tree removals. Because we credit PSEG LI's experience and recent bidding results as reliable guides to the cost per mile, and DPS Staff's proposal closely approximates the Company's cost estimates, we will accept the \$17.75 million as the budget for all three years.

Transmission Tree Trimming Program

The proposed annual funding level for transmission tree trimming is not disputed. 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).³¹ PSEG LI contends that documenting and reporting the ROWs is unnecessary and too costly (PSEG IB, pp. 39-40; PSEG RB, p. 14).

We recommend that PSEG LI follow Commission best practices regarding transmission ROW maintenance. These have been developed through experience with a variety of utilities. We see no reason why the best practices should not be applicable

³¹ 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).

and a useful guide to PSEG LI. DPS Staff notes that PSEG LI's performance in this area has been well below that of the other utilities in New York, which supports its argument that PSEG LI should follow statewide best practices (Tr. 1116-17).

We conclude that PSEG LI should be able to provide a report to the Department by the end of 2017 on transmission ROWs. In its report, PSEG LI should also show how it will comply with Commission best practices going forward. Clearly, the Company should be able to coordinate with DPS Staff on the submission of documents needed that identify LIPA's ROWs. Its unsupported claim, that providing the documents would be too costly, is not persuasive. The Company already has maps identifying the transmission circuits and has records indicating the associated deeds and easements (Tr. 1062).

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 the alternative other records or documents needed and the costs to obtain them. The extent to which that information would satisfy the DPS Staff request or needs to be supplemented is unknown. The Company should 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. 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.

The Company also disagrees 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 believes that adopting the best practices should increase annual tree removals to the maximum ROW width (Tr. 1118). 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 that:

[a]s 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.³²

We would expect that PSEG-LI would utilize a similar practice already. Obviously, 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.

Providing a report to the Department on the 69kV and 138kV overhead transmission ROWs will 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

³² Case 04-E-0822, supra, June 2005 Order, p. 24.

information should also assist the parties in reaching a resolution of the appropriate trim cycle for the system.

Pole Inspection Expense³³

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).³⁴

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 proposes 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).³⁵

DPS Staff concurs with maintaining the current 10-year cycle. However, DPS Staff disagrees with the overall number of poles remaining to be inspected by 2022, PSEG LI's proposed

³³ There appear to be no disputed issues with respect to transmission pole inspections.

³⁴ 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 ($325,000 + (1,500 \times 10 \text{ years})$) (see, e.g., Tr. 1076). As noted later, the correct number of LIPA-owned distribution poles is 324,771 (Tr. 1023, 1125).

³⁵ 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.

total budget, the number of poles targeted for inspection each rate year, and the cost and extent of the planned distribution pole inspections and treatments. DPS Staff estimates that 325,499 distribution poles remain to be inspected during 2016-2022 (DPS IB, p. 18).³⁶ 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 proposes 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 states that excavation costs should be reflected as treatment costs and not inspection costs, and proposes 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).

PSEG LI explains that it is attempting to craft a remedial program. It argues that, by accelerating its pole inspection and treatment program during the rate plan, its proposal will improve reliability and keep the pace of inspections to remain on target for achieving a 10-year inspection cycle. It also argues 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 will 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,

³⁶ 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).

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 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).

PSEG LI's justifications for its proposal to provide for a more comprehensive inspection protocol than that proposed by DPS Staff are persuasive. 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, 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). These factors seem to warrant providing funding at the levels proposed by PSEG LI.

However, we share 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. Also, 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 to maintaining the existing 10-year cycle. Therefore, we recommend 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. 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.

As we also share DPS Staff's concern about being able to track and assess the proposed inspection and treatment plan, we recommend that PSEG LI be required to separately track such costs, consistent with the DPS Staff's proposal in its briefs (DPS IB, p. 19; DPS RB, p. 14). PSEG LI therefore should separate such costs for accounting and tracking purposes, even if, in practice, the activities that form the basis for such costs are performed contemporaneously.

Finally, DPS Staff correctly observed that the number of distribution poles remaining to be inspected during the period 2016-2022 should be reduced to reflect the inspections that PSEG LI indicates will have been completed by the end of 2015. We therefore clarify that our estimate of the number of distribution poles remaining to be inspected during the period 2016-2022 is 319,760, which we calculated by starting with the correct number of LIPA-owned distribution poles (324,771), subtracting the number of poles that PSEG LI indicated would be inspected by the end of 2015 (15,551), then adding PSEG LI's estimated number of poles to be re-inspected (1,500 annually for 7 years, or 10,500). Using this total, and performing inspections at the rate of 45,680 poles per year from 2016-2022 would keep PSEG LI on the current distribution pole cycle of 10 years and allow for the inspection of all of the LIPA-owned distribution poles plus re-inspection of 1,500 such poles for the next 7 years.

In sum, we recommend a distribution pole inspection/treatment budget of approximately \$2.15 million per

rate year. This funding amount was determined by multiplying \$3.2 million (PSEG LI's proposed total funding level) by 67 percent (45,680/68,000). 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 we recommend, 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.

BES Staff Funding

PSEG LI seeks \$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), approved in December of 2012 by the Federal Energy Regulatory Commission (FERC).³⁷ DPS Staff recommends setting the funding level at \$450,000.

In addition to two 345 kV circuits covered under the prior BES definition, there are now 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 states 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

³⁷ 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).

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 estimates of the total number of annual labor hours needed to accomplish each function (Tr. 1027-30, Exh. 68). It maintains that seven employees will be needed at a cost of \$1.55 million (Exh. 71, pp. 260-63; Tr. 1026).³⁸ However, PSEG LI notes 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 personnel (Tr. 1030; PSEG LI IB, p. 54).

DPS Staff points out that PSEG LI initially categorized the additional work as non-labor, later correcting it to show the costs as all labor. In addition, it says 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 argues that, in view of the limited information PSEG LI provided for review and inconsistencies between the Company's discovery responses and

³⁸ 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).

its rebuttal testimony, the incremental labor allowance for BES staffing should be cut in half to \$450,000. PSEG LI contends that DPS Staff's recommendation is arbitrary and unsupported because no workpapers or backup was provided to support the \$450,000 amount (PSEG RB, p. 19).

The additional work presented by the change to the BES definition and increased system assets covered by the new requirement will be significant. Setting an appropriate allowance for new staffing is complicated by the 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 Company indicated under the category of Transmission Operations that Training Development/Maintenance and Training Delivery will consume over 1600 hours annually (Exh. 68). It seems unreasonable that the same amount of training will be required annually. Absent disclosure of what specifically is envisioned for the BES activities, there is no way to ascertain whether the annual man-hour projections for the various tasks are reasonable. PSEG LI has the burden of demonstrating the reasonableness of its recommendation. We agree with Staff that PSEG LI has not met that burden here. Therefore, we adopt the Staff adjustment. We recommend the \$450,000 annual funding level for the term of the rate plan.

REV Staffing

PSEG LI requested \$900,000 of incremental costs to identify and analyze alternative solutions related to the Reforming the Energy Vision (REV)³⁹ initiative in 2016, 2017, and 2018. DPS Staff recommends that these costs be eliminated from

³⁹ Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

the revenue requirement, and instead be 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 explains 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 observe 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 recommends 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 proposes 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 recommends 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 objects to DPS Staff's recommendation to exclude \$900,000 of proposed incremental costs from the revenue requirement. It asserts 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 adds that such work will need to be performed now, regardless of whether an alternative is ultimately selected. PSEG LI also asserts 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).

We recommend the adoption of DPS Staff's proposal. 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). Also there is uncertainty as to the timing and implementation of possible REV alternatives. And, while PSEG LI asserts that it intended to identify only the incremental cost of the REV alternatives analyses, costs that are not otherwise reflected in the revenue requirement, the exhibits (69 and 70) and testimony (Tr. 1031-33) cited for that purpose fall 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. Moreover, the evidence does not provide any indication of when such costs will actually be incurred.

The proposal recommended by DPS Staff addresses PSEG LI's cost recovery concerns by providing for cost recovery regardless of when or if a REV alternative solution is selected. The DPS Staff recommendation addresses 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) proves insufficient for covering costs of analyzing REV alternatives. 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.⁴⁰ 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).

Enterprise Resource Planning System (ERP)

Nassau asserts 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 adds 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 responds that the County's claim was refuted in PSEG LI's rebuttal 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). It also highlights testimony that the capital budget for 2015 was approved by LIPA as part of

⁴⁰ 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.

its normal processes and was subject to public scrutiny and hearings (Tr. 1409-10). PSEG LI notes 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 argues 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 notes 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.*). We find that PSEG LI's rebuttal testimony provides ample and persuasive justification for rejecting the County's position regarding ERP costs.

Productivity

A dispute exists between DPS Staff and PSEG LI here 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 opposes the DPS Staff productivity adjustment. Alternatively, it suggests that, if the DPS Staff productivity adjustment methodology is 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 asserts, 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 amounts to a "heads I win, tails you lose" approach (PSEG IB, p. 73).

PSEG LI first argues that no productivity adjustment should be imposed in this case because, the Company argues, such an adjustment would be contrary to both the OSA and the LRA (PSEG IB, pp. 67-71). This is so, PSEG LI argues, 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 argues, 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.

PSEG LI belies its own arguments, however, by asserting that it has imposed a productivity adjustment on itself. PSEG LI explains that it started with projected budgets for the years 2016-2018 for labor and benefits, and then imposed an escalating productivity adjustment over the three years to reduce the forecast of labor expenses during the period. By doing so, it seems to acknowledge that building an efficiency incentive into LIPA's rates for the coming period is an appropriate means for cost curtailment on the part of PSEG LI in performing its operations under the OSA. Consequently, we reject the argument that a productivity adjustment is inherently inconsistent with the process of evaluating rates in this matter.

PSEG LI further argues that DPS Staff's productivity adjustment is 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, offsetting the productivity adjustments with known savings is contrary to the nature of the adjustment, which is expressly designed to apply to undefined savings that have yet to be identified. Therefore, we are not persuaded that DPS Staff's adjustment is necessarily overstated for this reason.

PSEG LI further challenges the DPS Staff adjustment on the grounds that DPS Staff used an inappropriate base number for labor and benefits in calculating the adjustment (PSEG IB, p. 72). The parties acknowledge that DPS Staff's calculation is applied to the GAAP costs calculated for PSEG LI's labor and benefits, whereas LIPA's rates use ERISA funding for pensions and cash accounting for OPEBs. As a consequence, the Company

asserts, 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 funding for OPEBs, the difference 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 is recovered via financing costs versus expense recovery is a distinction without a difference, says DPS Staff. DPS Staff's rejoinder makes sense. If the total against which we would normally make a productivity adjustment is merely moved from one recovery allowance to another, that does not seem to negate the validity of the adjustment. We would not reject DPS Staff's adjustment on that basis.

We 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. Consistency dictates that the 1 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 are \$0.627 million in 2016, \$1.927 million in 2017, and \$4.701 million in 2018.⁴¹

The Company asserts that its own productivity imputation is a higher total over the three years than DPS Staff's adjustment (PSEG IB, pp. 73-74). Because the Company's adjustment is weighted toward the third year of the rate plan, however, it is not correct that the Company's adjustment would

⁴¹ These figures differ slightly from those the parties refer to in their briefs (PSEG IB, p. 67, n. 37 & p. 73), which refer to initial testimony and work papers. We rely here on the updated figures reflected in Exhibit 76.

result in higher savings for ratepayers over the three years of the rate plan. On the contrary, the cumulative impact of DPS Staff's adjustment represents greater ratepayer benefits, even with our modification of the 2018 imputation. Consistent with the Department's mandate to recommend rates set at the lowest level consistent with sound fiscal operating practices, we find that the DPS Staff methodology should be applied consistently throughout the three-year period. The resulting adjustments are (\$1.735 million) in 2016, (\$0.469 million) in 2017 and \$2.257 million in 2018.

Escalation Factors/Inflation

The parties disagree over the proper rate 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 administrative services beginning in 2017 when the existing contract expires and for its 401(k) plan. It assumes 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 2.5 percent, which the Company used as its forecast of annual inflation (Tr. 664-65; PSEG IB, p. 81-82).

In contrast, DPS Staff asserts that none of these escalation factors proposed by PSEG LI is sufficiently justified or documented to be considered a known increase (Tr. 73). Consequently, DPS Staff proposes instead to escalate all these expense categories by the rate of inflation (Id.). Moreover, DPS Staff differs 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 estimates of the GDP-IPD inflation rate 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 charges that the DPS Staff adjustment contravenes both the OSA and the LRA (PSEG IB, pp. 82-87). It notes that under the OSA, PSEG LI has the right to pass through expenses, such as wages, benefits, and costs for outside services. It asserts 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 asserts 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.

We believe PSEG LI has misunderstood and mischaracterized the DPS Staff adjustment. 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),⁴² 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 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

⁴² 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.

singled out to be escalated at a rate higher than the 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.⁴³

DPS Staff has conceded, and we agree, that any known, determined costs should be factored into the Company's forecasts. For example, as the Company mentions, if there are contractual provisions, such as union contracts or leases, that call for specific increases in the future, they should be used in the Company's forecast. Here, however, the Company's forecasts were not based on any known increases in the categories of cost at issue. Rather, the Company's witnesses testify essentially to their best judgment in making an educated guess as to the likely cost escalations in the various categories. In this situation, the most accurate means of predicting future prices 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 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 it works reasonably well, there is no contravention of the OSA or the LRA, nor is there any unfairness to LIPA or PSEG LI.

We further support DPS Staff's reliance on the GDP-IPD as the best measure of inflation to use for rate-setting purposes. DPS Staff testified that the GDP-IPD is a measure of the overall national economy and is, therefore, more indicative

⁴³ 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.

of the commercial activity of a utility than the Consumer Price Index (CPI), which is a measure of consumer activity (Tr. 74). In contrast, PSEG LI does not sufficiently justify its choice of 2.5 percent with its statement, in its brief, that the rate is "close to" the 2.3 percent average CPI forecasted by the Congressional Budget Office (PSEG IB, p. 87-88).

Applying these general principles, we find DPS Staff's approach to union wages to be reasonable. There is actually little difference between PSEG LI and DPS Staff on this issue, since both agree that the known contractual increase for 2016 should be used in the forecast, followed by a general inflation factor to forecast the remaining years. Because we prefer DPS Staff's inflation estimate to the Company's, we agree that union wages should be increased by 2.1 percent, rather than 2.5 percent, for 2017 and 2018.

We recommend adoption of PSEG LI's estimate, and rejection of DPS Staff's adjustment, for the salaries for the MAST employees, subject to confirmation through the exceptions process. PSEG LI's Wages, Salary and Benefits Panel testified that salary estimates for these employees were escalated by 3 percent, based on "a review of various compensation surveys of projected merit and total salary increase budgets, as well as a review of past history" (Tr. 827). Ordinarily, we would expect to see such a statement backed up by submission of the actual compensation surveys or at least testimony from DPS Staff that the back-up material had been reviewed and verified. In this case, it is not clear whether the back-up information was ever provided to Staff (PSEG RP, p. 35). In any event, it does not appear to be included in the record, but the testimony and briefs suggest that the compensation studies do exist and could be made available. Moreover, the 3 percent escalation factor does not seem unreasonably excessive on its face. Therefore we

recommend adoption of the Company's forecast of MAST salaries, subject to the Company's provision of the supporting documentation. PSEG LI should file the supporting information within two business days from the release of this recommendation, and should indicate whether the information was previously provided to the parties through the discovery process.

We note that, on the current record, the Company's forecast labor costs for the rate period are not broken out between union and MAST employees. Given our recommendation here, such information is critical to calculation of revenue requirement and the setting of rates in this case. Moreover, as we note elsewhere in discussing updates and a second stage filing, such information will also be necessary to evaluate the updates expected to come in later stages of this proceeding. For the present, we estimate that union payroll represents 64 percent of the total payroll presented by PSEG LI. PSEG LI should provide a breakdown of the budgeted 2015 and 2016 operation and maintenance labor costs for union and MAST employees, respectively with supporting backup in its brief on exceptions and continue to provide such information to DPS Staff when it submits future updates.

We agree with DPS Staff that costs for medical, prescription drug, dental, and benefits administration should be escalated by a general inflation factor. There is no indication in the record of known increases in these costs under contractual provisions. Indeed, there is 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 increases would likely increase by more than the 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, those costs should also be brought under the general inflationary increase.

In contrast, at least some of the business services budgets were developed with known future costs in mind. We would therefore adopt that much of the Company's business service budget that is based on long-term leases or quotes from its insurance broker, and similar information (Tr. 664). It appears, however, that there is insufficient detail in the record that would allow for one to parse out those expenses from the others with which they are bundled (Exhs. 64, 65). 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, it appears that the forecast for those expenses is reasonably fairly done, except for the use of an inappropriate measure of inflation. Our best remedy would be to reduce 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.

Finally, we note that, although the DPS Staff adjustment affects the escalation of PSEG LI's T&D, customer service, and power markets budgets, PSEG LI did not respond specifically to the adjustment with respect to those categories, nor did the parties address the matter on briefs. Given that PSEG LI had the burden of demonstrating the reasonableness of its requested rate relief 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, we adopt the DPS Staff adjustment as to those

budgets, to the extent not otherwise addressed specifically above.

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 supports 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.⁴⁴

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 proposes 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 proposes to increase its direct-mail budget from \$200,000 in 2015 to \$939,000 in 2016. For its media budget, PSEG LI

⁴⁴ DPS Staff's general adjustment to PSEG LI's escalation of labor rates and forecast inflation rate also impacts PSEG LI's customer services budget.

proposes 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 proposes 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 proposes to disallow nearly the entire \$878,000 increase, with adjustments of \$327,000 for TV campaigns and \$550,000 for increased media outreach.⁴⁵ In total, DPS Staff's adjustment would reduce PSEG LI's requested increase by \$1.48 million (Tr. 627).

DPS Staff articulates a number of reasons for its proposed adjustments, only some of which we find persuasive. DPS Staff cites to its Exhibit 85, SCSP-2, as the backup for its calculations. However, that exhibit shows DPS Staff's calculation of total LIPA revenues, multiplied by 1/25 of 1 percent, as equivalent to \$1.5 million. DPS Staff goes 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 1 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 states that PSEG LI has not justified the need for the full increase nor provided a clear

⁴⁵ The \$1000 discrepancy between the total proposed increase and DPS Staff's characterization of its adjustment may only be a function of rounding.

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 states that "the justification furnished by the applicant of needing to improve customer approval ratings in order to meet Operating System Agreement 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 states that the "overall reasoning" for its proposed increase to the outreach budget is 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 continues, "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 goes 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 will improve customer perceptions (Tr. 1373-84).

PSEG LI responds directly to the reference to the 1977 Advertising Policy Statement by stating that the information it intends 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 concludes, the outreach budget will 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 argues that the provisions of the OSA require an increased budget as necessary to meet its performance metrics. It asserts 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 says (PSEG IB, p. 101). Moreover, even if the Advertising Policy were applicable, PSEG LI argues that the activities for which it seeks a budget increase are permissible expenditures of outreach funds under the policy. Granting it less than the amount necessary to meet its metrics is inconsistent with the authority granted to PSEG LI under the OSA, it asserts. Further, it states that it provided sufficient supporting information to justify its costs, explaining how its testimony shows the efficacy of communication via direct mail and mass media (PSEG IB, p. 103-04).

In its reply brief, PSEG LI argues 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 notes 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 complains of the ALJs' ruling denying it permission to introduce these information request answers into the record at the hearing, and submits that they would show, in detail, how the outreach dollars will benefit consumers (PSEG RB, pp. 42, 44-45).

DPS Staff notes that, under its testimony, PSEG LI would be entitled to an increase of \$619,000 in its outreach

budget for the first year. DPS Staff points to the Company's continual assertions that the need for the increase is based upon its desire to improve its customer satisfaction score, but states that the Company has 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 argues, satisfying the OSA metrics in the future should not require additional funding.

In its reply, DPS Staff further asserts that the Commission's Advertising Policy Statement is not the sole basis for DPS Staff's proposed adjustments to the budget. Rather, DPS Staff says the policy is relevant to DPS Staff's recommendation that PSEG LI implement measures to properly identify spending in that area. DPS Staff argues 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, we adopt the DPS Staff-recommended adjustments. We agree generally that PSEG LI has not adequately justified the need for such a dramatic increase in outreach spending. We agree further that the spending targeted particularly at mass media and direct mail is not justified by PSEG LI's record evidence explaining the reasons for it.

We need not resolve whether the Commission's Advertising Policy Statement is directly applicable here. As a general matter, we find it to be 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, we think the Policy Statement represents 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, there is no record basis here 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 - we 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 we be 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, we do not base our decision on reliance on the Advertising Policy Statement.

We assume that the customer satisfaction metric is designed to ensure that PSEG LI provides good customer service. 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. We agree that PSEG LI has not justified its need for the additional outreach spending, in that PSEG LI's primary justification has been that the spending will help it do well on the surveys, not that it will improve actual customer service.

It seems likely that most, if not all of the messages that PSEG LI intends 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, is not particularly helpful in deciding the issue here.) But merely demonstrating that the messages are appropriately educational and would be helpful is not sufficient to demonstrate that they are necessary or that the dramatic spending increase is a warranted ratepayer expense.⁴⁶ DPS Staff's adjustments, targeted at the direct mail and media categories of PSEG LI's spending, represent appropriate reductions to these campaigns (See Exh. 85, SCSP-1, p. 59 of 234).

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, 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

⁴⁶ For this reason, we see no prejudice to PSEG LI from the ALJs' refusal to allow it to enter its own witnesses' information request responses. It is standard practice in Departmental ratemaking cases that IR responses of a witness are properly offered and made part of the record by the opposing party, but are not allowed when offered by the witness's own party as merely self-serving attempts to bolster the record after the deadline for prefiling direct testimony. PSEG LI's responses were properly rejected on that basis. Here, we assume that they would show benefits to customers from the intended messages, but, as noted, that alone does not justify an increase in rates to fund them.

rate year reflect the latest and most accurate cost information available (Tr. 553-54).⁴⁷ DPS Staff expressed a preference for reconciliation information to be provided to it at the end of each year, 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 argues that incorporating the expenses into the delivery rates for the next year would avoid the rate shock that may be experienced from the implementation of various cumulative 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 explains it, the filing would capture known changes in: 1) the carrying costs of debt and current interest rates; 2) PSEG LI labor costs resulting from a new union collective bargaining agreement (CBA); 3) payments-in-lieu-of-taxes (PILOTs) on transmission and distribution property; and 4) unanticipated expenses incurred due to changes in federal, state or local laws, or rules, regulations and orders (Tr. 223-24; LIPA IB, pp. 34-36).⁴⁸ LIPA Staff recommends that the format of the second stage filing follow the format of Exhibit 5, the

⁴⁷ DPS Staff notes that the differences in LIPA debt costs would be recovered in the DSA along with T&D property tax and payment in lieu of taxes (PILOT) payments if the second stage proposal is rejected.

⁴⁸ The PSEG LI recommendation is consistent with LIPA Staff's. The Company delineated the description of the cost of debt category further, dividing it into two categories with the first related to debt service cost savings from two UDSA bond financings in 2016 and the second covering updates to debt service payments (PSEG IB, p. 96).

details of which it believes the parties do not dispute (LIPA IB, p. 36).⁴⁹

The Fall 2015 update for known changes would adjust the rates effective January 1, 2016. The Fall of 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 proposes that the stage filing process also 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 commits to 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 three parties all agree generally with the LIPA Staff proposal (PSEG IB, p. 97; DPS IB p.38-39, RB 25; LIPA IB, p. 36).⁵⁰ However, we seek some clarification from the parties regarding the scope of updates and subsequent filings. In its initial brief, LIPA Staff adds 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 does not mention these categories with respect to later filings. However, the attachment to LIPA Staff's reply brief includes these items in all subsequent update filings. In

⁴⁹ Exhibit 5 was prefiled as Exhibit___TF-1 Rebuttal.

⁵⁰ LIPA Staff noted in reply brief that the DPS Staff recommendation provides for updates in the Fall of 2015, a second stage filing in the Fall of 2016 and a third stage filing in the Fall of 2017, all of which are acceptable (LIPA RB, p. 25).

addition, it appears that LIPA Staff would also have the Department review the proposed DSA for each rate year of the three-year rate plan. The parties should comment in their briefs on exceptions on this scope of updates and second stage filings.

DPS Staff conditioned its agreement to include union CBA costs in the second stage filing on PSEG LI's 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 requests direct access into all modules of the Company's Systems, Applications and Products (SAP) financial system and available reporting tools, which DPS Staff claims 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 opposes 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 argues 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 is superfluous (Id.). Moreover, requiring direct access to all modules of the Company's SAP system has nothing to do with the second stage filing, says PSEG LI, and LIPA Staff has agreed to provide the information needed for DPS Staff to process the second filing (Id.). The Company concludes that the second stage filing should be adopted as outlined in its initial brief (PSEG RB, p. 41).

The parties aptly point out 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.⁵¹ In fact, 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.⁵² 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).⁵³

We support the update and staged filings process as described by LIPA Staff in its briefs. We concur with the DPS Staff position, that LIPA could recover the changes in debt costs, T&D property tax and PILOT payments under the DSA, if the update and stage filing process is not adopted, but to the

⁵¹ LIPA specifically cites to Case 08-E-0087, Central Hudson Gas and Electric Corporation – Rates, Order Approving Tariff Amendments on a Permanent Basis and Mandating Compliance (issued March 30, 2010), Appendix II; and Case 13-E-0030 et al., Consolidated Edison Company of New York, Inc. – Rates, Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal (issued February 21, 2010).

⁵² Cases 13-E-0030, Consolidated Edison Company of New York, Inc. – Rates, Order Adopting Terms of Joint Proposal to Extend Electric Rate Plan (issued June 19, 2015), p. 36.

⁵³ The Company indicated that it was unable to provide historic cost information because National Grid did not transfer the financial data to PSEG LI until early 2015.

extent practicable, these costs should be reflected in LIPA's base delivery rates.

Although there were no objections raised by any parties to using the format in Exhibit 5 for the stage filings, we note that 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 have not independently expressed their agreement to adopt the revised Exhibit 5. We believe that it would be appropriate for the parties to advise us in the next brief to be filed in this matter, whether they are in agreement with the format and contents of the revised Exhibit 5.

Although it would have been preferable for DPS Staff to raise its request that the Company supply a calculation of total wages, broken down into union and non-union employees and referenced to work papers, earlier in this proceeding, we agree that the request is not only reasonable but essential to the rate setting process. As noted in our discussion of the inflation and other escalation factors proposed in this matter, we require that disaggregated information to determine a final revenue requirement in this case. We can foresee that the information will continue to be essential to evaluate the second stage filings. Therefore, we recommend that PSEG LI be required to supply the information.

The DPS Staff request in its initial brief, that it be granted direct access to PSEG LI's SAP financial system modules, also comes late in the process. According to DPS Staff, such access would expedite the Department's ability to review information and validate actual costs supporting the stage filing, assist in on-going monitoring of PSEG LI's actual costs in relation to forecasts, and minimize as much as possible the

amount of time that LIPA staff would need to be directly involved in the exchange of information. We note that the Department has access to the financial system modules at all of the other major electric utilities in the State. 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. To this end, the statute speaks to access to books and records,⁵⁴ which should encompass electronic records. Therefore, we recommend that PSEG LI be required to secure Department access to the SAP system, and invite the parties to address this issue on exceptions.

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 are 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 the storm event, reemphasizing that the report would be narrowly focused to

⁵⁴ PSL §3-b(4). We note that this section of the law grants DPS access to books and records "[t]o undertake the requirements of subdivision two of this section." The clear intent was to refer back to subdivision (3), setting forth DPS' powers, rather than subdivision (2), the definition section.

include only straight-time labor (DPS IB, p. 36; DPS RB, p. 19). In its briefs, DPS Staff clarified that it is not suggesting PSEG LI provide a report after every storm event. Rather, DPS Staff says 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 asserts 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 (DPS RB, p. 19).

PSEG LI states 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).⁵⁵ Moreover, it claims 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 states 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).

⁵⁵ The Company's witness noted that in years where there are significantly more major storms than normal, transmission and distribution employees are required to spend a greater amount of straight time on storm related work, with the result that their base work may not be completed (Tr. 450).

We agree with DPS Staff that the scope of information requested – straight time labor – is very narrow. We also agree with DPS Staff that this 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. PSEG LI could note in the report if information provided is preliminary and needs further verification, and then state when it expects a final to be submitted. Thus, submitting straight time labor reports would not present onerous workload and timing burdens on PSEG LI. Moreover, 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)).

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 states in its rebuttal testimony and brief that it supports the DPS Staff recommendation (Tr. 453; PSEG IB, pp. 90-91). The Company highlights 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 points 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 storms cannot be so 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 pledges 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 responds 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 says, 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.).

We believe it is of great importance that PSEG LI properly prepare for storms and support any effort to ensure that it has the proper incentive to do so. We support the suggestion of DPS Staff insofar as it contemplates that PSEG LI will provide DPS Staff with complete information about its storm preparations and the cost thereof, even in cases where the storm fails to materialize, and we further support the idea that DPS Staff should review such information and report to the LIPA BOT regarding DPS Staff's assessment of the reasonableness of PSEG LI's actions and the costs incurred. However, we agree 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. We recommend 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.⁵⁶

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 for a 2015-2018 projected storm reserve budget of \$48.597 million, \$48.169 million, \$49.077 million, and \$50.199 million, respectively. DPS Staff agrees and supports 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,⁵⁷ a deficit remained in the storm reserve, one-third of the under-recovered amount would be recovered from ratepayers through the DSA (Tr. 746).

⁵⁶ PSL §3-b(3)(h).

⁵⁷ The tracking period in 2016 is only nine months, January 1, 2016 through September 30, 2016. Thereafter, the tracking periods correspond to years ending September 30 (Tr. 745).

DPS Staff generally supports 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 its 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 notes that there would be no funding cap for 2016 since collections would commence in January 2016 and not reach the maximum level in that year (Tr. 510). If the collections cap is 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 will 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 continues to assert 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).⁵⁸

Costs associated with storm events are very difficult to forecast with any degree of accuracy. As LIPA Staff points 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). Therefore we agree with the parties' proposals for a larger storm reserve account, capped at \$75 million. Using any

⁵⁸ DPS Staff calculated the 1.5x rate allowance for the storm reserve to be \$73.65 million in 2017 and \$75.3 million in 2018 (Tr. 510).

surplus funds in the account to offset future borrowings benefits ratepayers because they would not incur the additional costs and carrying charges associated with the financings.

We do not find that setting the cap at 1.5 times the DPS Staff-recommended rate level would result in any better certainty for the utility or consumers. In contrast, setting the cap at a fixed amount provides a transparent, simple and readily verifiable way to track annual storm reserve funding and ensure that any excess funds in the storm reserve account are used for the intended purpose. Therefore we reject SCL's recommendation to adopt the storm reserve funding cap at the lesser of 1.5 times the DPS Staff's recommended base rate storm reserve allowance or \$75 million.

Proposed Storm Hardening Collaborative

NYC, joined by NRDC, SCL, and SCC, recommend 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 notes that, well before Hurricane Sandy, LIPA commenced a 20-year, \$500 million storm hardening program. NYC however states that the annual average spending of \$25 million under this program is insufficient with respect to the scope and speed of deployment needed to address present climate threats to LIPA's infrastructure.

NYC also observes 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 says they are inadequate to protect the system against

current and future climate risks. NYC says 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 notes 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 adds 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 states 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 indicates 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, opposes what it sees as NYC's efforts to dictate how the collaborative should be structured and what studies should be performed.

PSEG LI asserts 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 adds that it has performed associated modeling, and incorporated the results into system improvements. It says 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 adds 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 expresses 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 says 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 expresses 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 concludes there is no need for DPS to address NYC's recommendations with regard to establishing a storm hardening collaborative. DPS Staff asserts that conducting a collaborative for storm hardening would not be productive at this time and should not be explored.

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. We, therefore, recommend 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. We do 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.

Transmission & Distribution Capital Budgets

Loading Factors

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 proposes negative adjustments of \$47 million in 2016, \$47 million in 2017 and \$78 million in 2018 (DPS IB, p. 16). DPS Staff asserts 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 assert that the costs at issue are real costs that are incurred in capital programs (LIPA IB, p. 39).

PSEG LI acknowledges 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 states 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).

In its rebuttal testimony, PSEG LI provided plausible reasons why the costs at issue should, for the most part, not be duplicative and should be recovered as capital costs (131-36). It explains that 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). It adds that only after the approval and review process had been completed, and the SAP accounting platform had been implemented, did PSEG LI 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.

As these costs do appear to be properly classified as capital costs and are designed to reflect only incremental loading factors, we recommend that they not be excluded as DPS Staff proposes. However, there also appears to be some lingering confusion and uncertainty as to whether the applied loading factors are accurate and not more than they should be. They should, therefore be rechecked by PSEG LI to confirm that all of the loading factors have been fully and correctly updated and have not been applied to non-labor costs/contingency costs (see Tr. 164, 167). In its brief on exceptions, PSEG LI should confirm the loading factors have been fully and correctly updated and not applied to non-labor costs.

Old Bethpage Substation Construction Work

PSEG LI proposes 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 Staff'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. DPS Staff observes that as a result of the RFI, the proposed transmission line is temporarily on hold. DPS Staff therefore proposes an adjustment to remove the 2018 costs associated with the construction of the substation, as its construction is contingent on the construction of the feeder transmission line (DPS IB, pp. 26-28; DPS RB, pp. 17-18).

PSEG LI asserts 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 cites 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.).

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. The only dispute is whether the costs for construction that are proposed in 2018 should be recommended for approval. We agree with DPS Staff that the costs should not be recommended for approval at this time. There is too much uncertainty, including whether or when the project will be needed, whether

and when load will materialize or to what extent such load may be addressed by other means, such as REV related activity, and whether and when the transmission line to which it would need to be connected will be built. Moreover, the assertions that it would be too risky to exclude these costs are vague and unsubstantiated. We request 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 13.⁵⁹

Blanket Projects

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. PSEG LI aggregates projects having costs of less than \$1,000,000 each into blanket projects. Both specific, individual projects and blanket projects undergo review by the PSEG LI Utility Review Board (URB). However, because it 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 recommends 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 argues 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).

⁵⁹ For purposes of the revenue requirement calculation reflected herein, we use \$9.7 million.

PSEG LI asserts 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 argues 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 states 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 adds 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 concludes, 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 states 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 says 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 concludes that, absent a reason to 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, we adopt DPS Staff's proposal to lower the limit for projects that may be included under blanket projects to \$100,000. 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.

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). There is 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 opposes this reduction. It says 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 adds 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, we recommend that its proposed MCO budgets be adopted without modification.

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). 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). 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). Only DPS Staff addressed this issue in brief.

DPS Staff states that its adjustment removed abnormal spending in 2013 and abnormal projected spending for 2015. DPS Staff asserts 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). DPS Staff's position appears to be reasonable and does not appear to be contested. We recommend the adoption of the budgets proposed by DPS Staff.

Substation Control and Protection Improvements

Substation Control and Protection Program is a blanket program consisting of 18 subprograms geared towards improving Substation Control and Protection equipment to reduce the likelihood of equipment failures (Tr. 591). PSEG LI proposes 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 proposes 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). DPS Staff's recommendation should be adopted, reducing the Substation Control and Protection Improvements 2018 budget to \$3.72 million.

Utility Review Board Process

PSEG LI notes 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). However, it appears that only PSEG LI briefed this issue and it advocates no changes to the current process. Absent a countering argument, we accept PSEG LI's position.

AMI

The Company 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 to enable 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 reports 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 anticipates that AMI deployment at the scale it proposes will 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 the following 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.

Beyond the 2015 proposal, DPS Staff opposes the deployment proposed by PSEG LI, finding the proposed roll-out not well defined, inconsistent with existing Commission policies in that it does not require large commercial customers to pay for their AMI meters, and not sufficiently supported by a benefit/cost analysis. Specifically, DPS Staff notes 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 recommends 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 recommends beginning deployment with these larger customers until the Company has gained sufficient experience with the new rate design (Tr. 1509-11).

PSEG LI characterizes DPS Staff's proposal as impractical because customers with demand exceeding 300 kW are spread across the territory and, therefore, the CPP program would not provide enough meter density to form an adequate "mesh network" to support reliable connectivity. Further, PSEG LI asserts 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 generally supports the deployment of AMI, but believes 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 proposes 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, can be submitted for Department review

by the end of 2015 as part of PSEG LI's next Utility 2.0 filing (Tr. 1269).⁶⁰

SCL asserts 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 recommends 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).

PSEG LI's AMI proposal is attractive in that it would set the stage for introducing REV programs as they develop. At this time, however, it is difficult to predict what role AMI will play in such programs and whether it will be necessary at the level envisioned by PSEG LI, where all customers would eventually have AMI. 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.⁶¹ For example, a report from the Market Design and Platform Technology (MDPT) working group in the REV proceeding recently noted that universal deployment of advanced metering may be unnecessary to meet REV objectives, and that utilities wishing

⁶⁰ PSEG LI intends to file an Integrated Resource Plan (IRP) by December 31, 2015. The next Utility 2.0 filing is due July 1, 2016. The IRP filed at the end of this year will incorporate programs contained in the existing Utility 2.0 plan.

⁶¹ 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), pp. 95-97 (Framework Order).

to deploy AMI across broad sections of their service territory should develop a business case premised on operational benefits, REV initiatives and a full benefit-cost analysis.⁶²

PSEG LI justifies the deployment of AMI with anticipated labor cost savings resulting from remote meter reading, major account management, billing and call center operations, but those anticipated savings have not been sufficiently established to fully justify the costs of the program at this juncture. Likewise, although PSEG LI notes additional benefits that AMI expansion will provide, relating to theft detection and investigations, high bill investigations, restoration costs, meter testing, unregistered meters, capacity and energy and demand response (Tr. 1397-98), it is not yet clear to what extent these likely, but as yet unmeasured, benefits will support the investment in AMI. DPS Staff points out various inconsistencies and shortcomings in the BCA analysis supporting the deployment which are troubling (DPS IB, p. 47-49).

Given these concerns, we are reluctant to recommend that the LIPA BOT commit ratepayers now to finance the significant investment envisioned in PSEG LI's rate filing. It also seems premature, on this record, to assume that DPS Staff's proposed CPP program is the most expedient course. Therefore, we recommend that PSEG LI's proposal be rejected and DPS Staff's recommended adjustments, but not its CPP proposal, be adopted. Nevertheless, we believe investment in some form of advanced metering will ultimately prove necessary and wise to support greater choice and innovation, such as creative rate design, more ability to manage load factor, creation of customer-facing

⁶² Report on the Market Design and Platform Technology Working Groups (filed July 15, 2015 at <https://newyorkrevworkinggroups.com>), pp. 92.

energy management software, active monitoring of real-time energy data, and the enablement of conservation voltage reduction to capture energy and peak reductions (Tr. 1392).⁶³ We anticipate that more detail regarding AMI implementation will likely be included in LIPA's next Utility 2.0 filing or, if possible, as part of PSEG LI's IRP to be filed by December 15, 2015 (Tr. 1269).⁶⁴ Accordingly, we recommend that actual amounts of AMI investment be updated and reconciled as part of the updates and second stage filing process.

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 LRA⁶⁵ 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).⁶⁶ Now, PSEG LI proposes 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 proposes 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

⁶³ Framework Order, p. 98.

⁶⁴ In making these future filings, PSEG LI should consider the proposal by the Town Board of Smithtown regarding a time variant pricing pilot.

⁶⁵ PAL §1020-f(ee); PSL §3-b(3)(g).

⁶⁶ Case 14-M-0101, Framework Order, pp. 10-13.

(Tr. 1493). While PSEG LI agrees that the TRC test should be calculated and considered, it maintains 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 points out that the TRC test fails to incorporate the impact of rebates and incentives, which can be critical to investment guidance. DPS Staff asserts 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 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).⁶⁷ 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.

Accordingly, we recommend that PSEG LI utilize the TRC in conjunction with the PAC. 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

⁶⁷ Case 14-M-0101, supra, Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding (issued July 1, 2015).

Con Edison's Demand Response and Brooklyn Queens Demand Management Programs,⁶⁸ and more completely reflects relevant costs. PSEG LI's concerns about factoring in rebates and incentives is mitigated because those considerations can still be captured by use of the PAC to choose between energy efficiency programs that also meet the TRC test. DPS Staff's recommendation that, 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. PSEG LI has expressed its willingness in working with DPS Staff to update the evaluation methodology as REV progresses (PSEG IB, p. 118). We are confident that steps in that direction can begin immediately to ascertain how best to incorporate both tests in the evaluation of the Utility 2.0 programs.

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 are the result of an annual 2.5 percent escalation rate.⁶⁹ DPS Staff asserts 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

⁶⁸ 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.

⁶⁹ These amounts will be offset each year by Regional Greenhouse Gas Initiative (RGGI) funds (Tr. 1480-81).

(Tr. 74). NRDC proposes 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.

We recommend that PSEG LI's proposed budgets be adopted, with DPS Staff's adjustment. 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 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, 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. 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 and which, after careful consideration, we 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 provides 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, the SCL suggests 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. We do not 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. We encourage SCL to 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 recommends 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).⁷⁰ NRDC's arguments in this regard should 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

⁷⁰ New York State Energy Planning Board, NY State Energy Plan (issued July 25, 2015) (<http://energyplan.ny.gov/Plans/2014.aspx>).

generation supply are being addressed separately in LIPA's Integrated Resource Planning process.⁷¹ 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.

Rate Design/Cost of Service

There appear to be 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, states that the following rate design and tariff changes also are 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;

⁷¹ Matter No. 15-00262, Ruling on Scope of Issues (issued March 30, 2015).

- 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 181; and
- Continuing a Revenue Decoupling Mechanism (RDM).

However, it appears that some of the above-mentioned proposals are still contested by SCL and DPS Staff, respectively.

SCL says that it opposes 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). It also suggests 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). SCL's arguments for modifying the RDM are not persuasive and have no support in this record. 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).

With respect to SCL's proposal to adjust the DSA more frequently than once a year, LIPA Staff argues 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. Instead, says LIPA Staff, 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, we agree that the frequency of resetting the DSA should not be modified.

In addition, SCL also opposes increasing the Large Commercial Customers (LCC) demand charge (SCL IB, p. 6). 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 (Tr. 1220-21). SCL's opposition and proposed alternative increase is not based on similar review and has no cited record support. Therefore, SCL's position should not be adopted.

DPS Staff indicated that it opposes 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 turn-offs as part of its investigation fees. DPS Staff does not support this proposal because it asserts that LIPA's tariff already provides for the inclusion of investigation fees when theft of service occurs and DPS Staff posits that such fees should have the deterrent effect that PSEG LI seeks. DPS Staff thus recommends that PSEG LI and LIPA be precluded from modifying LIPA's tariff to include the proposed Removal Charge (DPS IB, p. 44). We agree with DPS Staff that the proposed tariff language seems to

provide for a charge that would be duplicative and therefore unnecessary. We recommend that the proposed charge and tariff language not be approved.

Residential and Small Commercial Customer Charge

PSEG LI 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).⁷² LIPA Staff states 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 suggests 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.

Track Two of the Commission's REV proceeding is expected to include a full examination of the current rate structures and designs (Tr. 1212). As a result, we find that making changes to existing rate design now would be premature. Accordingly, we recommend 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. Consistent with this recommendation, the proposals to increase the low-income discount should also be postponed as they were intended

⁷² UIU, NRDC, SCL, and SCC also oppose increasing customer fixed charges.

to offset any proposed increases in the residential customer charge.

Phase-out of Grandfathered Residential Water Heating

PSEG LI proposes to eliminate and phase out Residential Electric Water Heating over the three years of the rate plan. DPS Staff agrees with eliminating the class but proposes a five-year phase-out. SCL opposes 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. PSEG LI's stated reason for eliminating this rate is that it wishes to discontinue a discriminatory rate treatment that could no longer be justified. PSEG LI adds that its proposed three-year phase-out produces bill impacts that, on average, are below the 11 percent benchmark identified by DPS Staff (PSEG IB, p. 131; PSEG RB, p. 55).

DPS Staff argues that water heating service has been grandfathered and closed to new customers since 1983, so its elimination is not unreasonable. DPS Staff however recommends a more gradual phase-out over five years, saying it would avoid rate shock, be more equitable, and allow customers time to make decisions concerning heating choices (DPS IB, p. 54). In response to SCL's concerns, DPS Staff notes that end-use rates, like water heating, have been eliminated from NYS electric tariffs because they provide favorable rate treatment, but only for customers with certain end-use appliances. DPS Staff adds that migrating customers from such rates to time-of-use alternatives is preferred and has been pursued at all other NYS utilities. Finally, DPS Staff notes its expectation that residential rate structures, including time-variant rate alternatives, will be addressed under Track Two of the REV proceeding (DPS RB, p. 42).

We are persuaded that there is sufficient justification for eliminating this service classification but, for the reasons articulated by DPS Staff, we recommend that it be phased out over five years.

Rate Counseling for Rate 285 Customers

SCL recommends that PSEG LI offer counseling to Rate 285 customers to help them ascertain whether they are on the appropriate billing rate. PSEG LI should respond to this recommendation on exceptions.

Online Bill Calculator

SCL recommends 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 (SCL IB, p. 2). We encourage LIPA Staff and PSEG LI to respond to this proposal on exceptions.

Recalculation of the Cost-Based Seasonal Rate Differential

PSEG LI initially proposed elimination of 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 asserts, without further explanation, that it recommended a new or updated cost-based seasonal differential, which it recommends to be applied by service class to set winter/summer seasonal rates (Id.). LIPA does not comment specifically on the seasonal rate differential. It does comment generally, however, stating that consideration should be given to implementing as many rate design proposals during this proceeding as are consistent with the rate design of other NYS utilities (LIPA IB, p. 45). DPS Staff, UIU and the SCL support

retention of the seasonal rates (Tr. 1224; DPS IB, pp. 56-58; UIU IB, p. 3; SCL IB, p. 3).

The Company states that eliminating the seasonal differences in rates would assist in presenting a simple and understandable flat rate (Tr. 730; PSEG IB, p. 125). It further states that seasonal rates are not cost-justified and that 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 says, which eliminates the price signal to conserve energy associated with higher rates in summer months (Id.). PSEG LI also claims that 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).⁷³ Not only have the energy costs been removed from delivery rates, says PSEG LI, but summer billing determinants have increased due to increased use of air conditioning, in particular central air conditioning (Id.).

The Company asserts that the T&D system costs do not vary season by season even if system loads change month-to month (PSEG IB, p. 127). Delivery rates collect delivery costs, it says, which do not materially vary by seasons (PSEG RB, p. 56). The Company 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 says, based on the premise that a generator choosing to build a baseload or peaker

⁷³ The Company indicates 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).

unit must consider tradeoffs between capacity and energy costs (PSEG IB, p. 127). Its witness has calculated and presented seasonal rate differentials based on the remaining generation capacity costs still in delivery rates, and that calculation should be used in setting seasonal rates, rather than adopting the DPS Staff proposal, which it says maintains the differential based on an outdated study (Id.). PSEG LI, however, stated 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 emphasizes 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 contends 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 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 says 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, says DPS Staff, whose electric facilities are stressed by increased air conditioning loads in response to high summer temperatures and an influx of summer visitors (Id.). It

concludes that adopting PSEG-LI's proposal would have the adverse effect of encouraging peak load growth (Tr. 1222).

DPS Staff acknowledges 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. DPS Staff states 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 states 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, DPS Staff says, should assist in meeting the PSEG-LI goal of helping commercial customers manage cash flows (Id.).

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 Company's contention that there is no need to have higher rates in summer when customers are already overburdened by their high utility bills because of usage fails 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. We note, that, 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. These customers, in particular, are affected by the seasonal differential.

We acknowledge that LIPA offers a balanced billing option. However, we disagree with the Company's claim that the billing option eliminates the price signals associated with higher summertime delivery rates (Tr. 774). 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.

We do 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. Aside from PSEG LI's assertion, there is no evidence in the record to suggest that commercial customers are experiencing difficulties managing their cash flows as a result of the current rate structure. Moreover, without this showing, the existing filed rate is presumed to be just and reasonable.

Lastly, we note that overall rate design is an integral component of the ongoing REV proceeding.⁷⁴ As indicated in a recently issued Department whitepaper, 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."⁷⁵ Seasonal rates are clearly related to the broad rate design

⁷⁴ 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).

⁷⁵ Case 14-M-0101, supra, Staff White Paper on Ratemaking and Utility Business Models (July 28, 2015), p. 95.

policy considerations and could be directly or indirectly affected by REV rate design changes. And, DPS Staff noted that REV Track 2 is expected to include a full examination of current rate structures and designs (Tr. 1212). It would, therefore, be reasonable to avoid making changes in the existing seasonal rates for LIPA in the interim. We, therefore, recommend 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.

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 is recommending 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).⁷⁶ It 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 illustrates 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

⁷⁶ The Company indicates that the increase in the demand ratchet is based on its study of over 48,000 customers on Rate Code 281 (Tr. 734).

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 calculates, 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. That 15kW increase over the customer base in Rate Code 281 would produce 12.95 percent more billing units, lowering the demand rate (PSEG IB, p. 128).

The Company asserts 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 states 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 says, 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 better aligns 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 oppose 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).⁷⁷ DPS Staff argues 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.⁷⁸ Moreover, it argues 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).

We find the record is insufficiently developed on this issue to recommend supporting the Company's proposal at this time. The Company does 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 is 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 this document, the REV proceeding is expected to consider myriad rate design issues. We believe 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, we share the DPS Staff and SCL concerns that the change in the winter demand ratchet might have adverse

⁷⁷ SCC states that the County invested over \$24 million in energy conservation measures over the past several years through the County's Energy Conservation and Demand Reduction measures, Capital Project 1664 (SCL IB, p. 5). A significant number of these projects were specifically designed to provide relief during high demand summer months (Id.).

⁷⁸ DPS Staff proposed that the customer charge and demand charge of Rate Code 281 customers be increased by 11 percent in each rate year (Tr. 1220).

implications on energy efficiency and REV resource development. Under the present circumstances we do not believe that the winter demand ratchet should be changed until there is a complete understanding of its implications on revenues and REV planning and resources. Therefore, we recommend that PSEG LI's proposal to increase the winter demand ratchet be denied.

Residential Electric Space Heating

DPS Staff proposes 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 disagree, urging retention of the space heating rates (PSEG IB, pp. 129-31; SCL IB, p. 4). Although not addressing this issue specifically, LIPA staff states that it, 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.

According to DPS Staff, 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 says, 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 acknowledges that the phase-out will result in higher rates for these customers, and states that minimizing customer bill impacts is the reason for proposing a phase-out of the rates over five years (DPS RB, p. 41). It notes further that the impact of the increases on electric space heating customers could be mitigated through TOU rate alternatives, which the Commission supports (Id.).

SCL's is opposed to any reduction or elimination of the space heating rate; it argues 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 the higher rates they will be charged or through purchasing replacement heating systems (SCL IB, p. 4). SCL contends 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 references three principal reasons why it opposes elimination of the space heating rate. Specifically, it argues 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).⁷⁹ According to PSEG LI, this rate change alone will 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).⁸⁰ It also points out that DPS Staff cited bill impacts as the reason for rejecting other Company proposals for eliminating the grandfathered residential water heating rate; increasing customer charges; increasing commercial customer demand charges;

⁷⁹ PSEG LI points 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).

⁸⁰ The Company indicates 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).

and increasing the large commercial customer winter demand ratchet to 85 percent (PSEG IB, p. 130). The Company avers 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.).

We acknowledge that the existing electric space heating rates, similar to the grandfathered residential water heating rates discussed earlier, only apply to certain end-use appliances, and that differentiating rates on this basis is not recommended. However, we do 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 indicates the elimination of the space heating rates would have a substantial impact on annual customer bills. Although DPS Staff claims that the economic impact on these customers could be mitigated by moving to TOU rates, there was no analysis provided to show how much of the increase would be mitigated by making such move. We note 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. Although we cannot predict what, if any, changes in heating appliances would result if the phase-out were to be adopted, there may be a potential for the phase-out to trigger heating appliance changes that might frustrate REV programs and technologies. This situation differs from that of residential water heating rates. Because those rates were closed to new customers decades ago, many customers have already likely begun to convert to more efficient equipment. For these reasons, we recommend that the DPS Staff proposal to phase out the residential electric space heating rates over five years be rejected.

Low-Income Program Outreach

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 recommends that PSEG LI adjust its HAR outreach efforts and programs to mirror the HEAP enrollment results (Tr. 635-37).⁸¹ DPS Staff, joined by the UIU, proposes 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

⁸¹ 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.

proposes the removal of the 50,000 customer cap on eligible customer participation under the HAR program (Tr. 636-37).

PSEG LI agrees with removing the HAR enrollment cap (see Exh. 35 (JTT-12, Schedule 1, Revised Leaf No. 188; PSEG RB, p. 46). PSEG LI also agrees with DPS Staff's recommendation to increase enrollment and participation in its HAR Program, but states 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 notes having reached out to OTDA for a database of such customers so it can match them to its customer database, but says that the OTDA was unable to provide this information due to privacy issues.

We recommend 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. Parties should look to examples from other NYS utilities, notably Con Edison, on how to develop seamless coordination between HEAP enrollment and HAR enrollment. In addition, we support removal of the cap for HAR participation. Given the importance of this program and its relatively low likelihood of a significant over-subscription, it is reasonable to remove the program cap at this juncture. Any program expenses that exceed the program rate allowance can be recovered through the RDM.

Moreover, we note that the low income program for PSEG LI may be informed by the outcome of the current Energy Affordability Proceeding pending at the PSC.⁸² AARP recommends

⁸² 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).

an increase in the discount provided by HAR, utilizing the methodology proposed in the Staff white paper recently submitted in that proceeding.⁸³ Because the Affordability Proceeding is still underway, it is premature to adopt AARP's recommendation. PSEG LI should, however, revise its program for rate year 2017 to reflect the best practices adopted by the PSC at the conclusion of the Affordability Proceeding.

Other Issues

Performance Ratios

Nassau argues 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 responds that Nassau 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 states 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 the County had only to review this information and ask any discovery related to it if it wanted information (Id.).

We find that the County's assertions regarding an alleged lack of information about performance ratios, or benchmarks by PSEG LI in its rebuttal testimony are misplaced and do not, in any event, provide sufficient or persuasive bases

⁸³ Case 14-M-0565, supra, Staff Report (June 1, 2015).

for its request that we recommend denial of the proposed rate increase. Moreover, the Department has reviewed OSA performance metrics, first in its review and recommendation on the Amended OSA,⁸⁴ second in the Department's review and recommendation on metric performance for 2014,⁸⁵ and third, more generally, in the review of this rate proceeding (e.g. storm reserve).

Request for NYS OSC Review

The Town of Brookhaven (Brookhaven or Town) requests variously that 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. Brookhaven made a similar request in an application it filed on May 14, 2015, in this matter, to which LIPA Staff responded. Brookhaven's requests that an invitation be extended to the NYS Comptroller from either the DPS, generally, or the ALJ Panel, specifically, are denied. We find it would not be appropriate for DPS to invite OSC to conduct such a review or to delegate binding approval authority to OSC.

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

⁸⁴ Matter 13-02006, In the Matter of a Review and Recommendation Regarding Proposed Amendments to the Long Island power Authority's Operations Services Agreement with PSEG Long Island LLC, Letter Recommending Approval of Amended OSA (September 27, 20103).

⁸⁵ Matter 15-01089, In the Matter of Long Island Power Authority Evaluation of PSEG-LI Performance and Incentive Compensation, Recommendations Regarding PSEG Long Island LLC Annual Incentive Based Compensation (June 15, 2015).

LIPA Board of Trustees.⁸⁶ The new rates will be set by LIPA, not DPS.⁸⁷ As LIPA Staff notes, there is nothing in the LRA that contemplates OSC rate review or authorizes DPS or LIPA to request OSC review.

Brookhaven cites 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). Brookhaven's case citations, however, do not support its position. Instead, 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 offers only one case where a public corporation invited OSC review. In Worth Const. Co., Inc. v.

⁸⁶ 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."

⁸⁷ 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.

Hevesi,⁸⁸ 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."⁸⁹ No such similar statutory provision authorizing DPS or LIPA to make such a request has been identified by Brookhaven here. Consequently, we conclude that it would not be appropriate for DPS to extend the invitation.

Moreover, none of the cases cited by Brookhaven hold that OSC supervision over "accounts" includes OSC review and approval of "rates." Brookhaven concedes that, in Patterson v. Carey,⁹⁰ 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. We are unwilling to accept that dicta as a basis to conclude that OSC review would be permitted in the instant matter. In fact, we note 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

⁸⁸ 8 N.Y.3d 548 (2007).

⁸⁹ PAL §362.

⁹⁰ 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.

upon OSC review and support.⁹¹ The lack of any cited precedent for OSC to conduct the binding review Brookhaven requests further supports our decision not to issue the invitation.

We also note 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. Given the general purpose of the OSC, it could easily have obtained party status. With party status, 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 OSC did not at any time request party status.

CONCLUSION

As we noted at the outset of this document, we have endeavored 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. Based on the entire record in this proceeding, our advisory staff expertise, applicable law, regulations and policy, we conclude that rates should be based on revenue requirements that increase by \$28.786

⁹¹ 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.

million in 2016, \$78.493 million in 2017, and \$81.267 million in 2018, as reflected in Appendix 1.

Long Island Power Authority and Subsidiaries
Matter 15-00262
Revenue Requirements per Draft 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 Draft Recommendation	As Adjusted per Draft Recommendation	Revenue Increase/ (Decrease)	Rate Year After Increase
Total Revenues	\$ 3,703,382	\$ (17,922)		\$ 3,685,460	(1)	\$ 12,494	\$ 3,697,954	\$ 28,786	\$ 3,726,740
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	28,786	2,044,910
PSEG Long Island Operating Expenses	496,306			496,306	(2)	(17,149)	479,158		479,158
PSEG Long Island Managed Expenses	587,159			587,159	(3)	(180)	586,979		586,979
Utility Depreciation	0			-			0		-
PILOTS - Revenue-Based Taxes	38,043		(505)	37,538	(1)	128	37,666	295	37,961
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		(17,200)	1,532,751	295	1,533,046
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		29,695	571,955	28,490	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)		\$ 29,713	\$ (28,490)	\$ 28,490	\$ -

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

	<u>Rebuttal As Adjusted by PSEGLI</u>	<u>Reclassify Public Power Adjustments</u>	<u>Initial & Reply Briefs Additional Adjustments</u>	<u>Final As Adjusted by PSEGLI</u>	<u>Adj No.</u>	<u>Adjustments per Draft Recommendation</u>	<u>Add Allowable Rate Increases</u>	<u>As Adjusted per Draft Recommendation</u>	<u>Revenue Increase/ (Decrease)</u>	<u>Rate Year After Increase</u>
Total Revenues	\$ 3,719,491	\$ (19,917)	\$ -	\$ 3,699,574	(1)	\$ 5,319	\$ 28,786	\$ 3,733,679	\$ 78,493	\$ 3,812,172
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	28,786	2,032,184	78,493	2,110,678
PSEG Long Island Operating Expenses	517,101			517,101	(2)	(17,861)		499,240		499,240
PSEG Long Island Managed Expenses	582,874			582,874	(3)	(337)		582,537		582,537
Utility Depreciation	0			0				0		-
PILOTS - Revenue-Based Taxes	37,889		(535)	37,354	(1)	54		37,408	798	38,206
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		(18,144)	0	1,555,697	798	1,556,496
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		23,463	28,786	568,695	77,695	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)		\$ 23,962	\$ 28,786	\$ (77,695)	\$ 77,695	\$ -

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

	<u>Rebuttal As Adjusted by PSEGLI</u>	<u>Reclassify Public Power Adjustments</u>	<u>Initial & Reply Briefs Additional Adjustments</u>	<u>Final As Adjusted by PSEGLI</u>	<u>Adj No.</u>	<u>Adjustments per Draft Recommendation</u>	<u>Add Allowable Rate Increases</u>	<u>As Adjusted per Draft Recommendation</u>	<u>Revenue Increase/ (Decrease)</u>	<u>Rate Year After Increase</u>
Total Revenues	\$ 3,726,435	\$ (22,160)	\$ -	\$ 3,704,275	(1)	\$ 1,020	\$ 107,279	\$ 3,812,574	\$ 81,267	\$ 3,893,841
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	107,279	2,098,322	81,267	2,179,589
PSEG Long Island Operating Expenses	523,962			523,962	(2)	(7,683)		516,279		516,279
PSEG Long Island Managed Expenses	581,506			581,506	(3)	(501)		581,005		581,005
Utility Depreciation	0			-				0		0
PILOTs - Revenue-Based Taxes	39,300		(2,071)	37,229	(1)	10		37,240	822	38,062
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		(8,174)	0	1,579,524	822	1,580,346
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		9,194	107,279	614,408	80,444	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)		\$ 10,833	\$ 107,279	\$ (80,444)	\$ 80,444	\$ -

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

<u>Explanation</u>	Incremental Totals			
	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>Total</u>
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		(28,786)	(107,279)	(136,065)
Add Revenue Taxes to LIPA/PSEG LI rate request	603	1,044	933	2,581
Adjusted LIPA/PSEG LI Rate Request	\$ 58,807	\$ 102,701	\$ 92,210	\$ 253,719
<u>Revenues</u>				
To adopt DPS' sales forecast increase	(12,494)	(5,319)	(1,020)	(18,834)
<u>PSEG LI Operating Expenses</u>				
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	(69)	(843)	(1,655)	(2,567)
To reflect Draft Recommendation adjustment to DPS' imputation of a 1% productivity adjustment	(1,753)	(473)	2,280	54
Total PSEG LI Operating Expenses	(17,327)	(18,045)	(7,761)	(43,133)
<u>PSEG LI Managed Expenses</u>				
Escalation adjustment for wages included in PSEG LI's Managed Expenses	(182)	(341)	(506)	(1,029)
<u>Debt Service and Coverage</u>				
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	(30,021)	(24,208)	(10,944)	(65,173)
Revenue Requirement per Draft Department Recommendation	\$ 28,786	\$ 78,493	\$ 81,267	\$ 188,546
Cumulative Revenues per Draft Department Recommendation	\$ 28,786	\$ 107,279	\$ 188,546	\$ 324,611

NOTE: The above adjustments include the effect of revenue taxes

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

<u>Adj. #</u>	<u>Explanation</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>Total</u>
1	<u>Revenues</u>				
	To adopt DPS' sales forecast increase	\$ (12,366)	\$ (5,265)	\$ (1,010)	\$ (18,641)
2	<u>PSEG LI Operating Expenses</u>				
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	(68)	(834)	(1,639)	(2,541)
m.	To reflect Draft Recommendation adjustment to DPS' imputation of a 1% productivity adjustment	(1,735)	(469)	2,257	54
	Total PSEG LI Operating Expenses	(17,149)	(17,861)	(7,683)	(42,693)
3	<u>PSEG LI Managed Expenses</u>				
	Escalation adjustment for wages included in PSEG LI's Managed Expenses	(180)	(337)	(501)	(1,018)
4	<u>Debt Service and Coverage</u>				
	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	\$ (29,713)	\$ (23,962)	\$ (10,833)	\$ (64,508)

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