

FOR CONSIDERATION

December 19, 2018

TO: The Finance and Audit Committee of the Board of Trustees

FROM: Thomas Falcone

SUBJECT: Recommendation for Approval of the Authority's 2019 Budget and Amendment of 2018 Budget

Requested Action

The Finance and Audit Committee (the "Committee") of the Board of Trustees is requested to adopt a Resolution recommending (i) approval of the proposed 2019 Operating and Capital Budgets (the "Budget") which sets forth the revenue, grant, other income, and expenditure forecasts for the year ending December 31, 2019, and (ii) amending the 2018 Operating and Capital Budgets, as described below and specified in **Exhibit "A"**.

Background on 2019 Operating and Capital Budgets

The proposed 2019 Budget totals \$4.468 billion, including an Operating Budget of \$3.599 billion and a Capital Budget of \$869 million. The proposed 2019 Operating Budget funds delivery and power supply costs, taxes and debt service. The Capital Budget funds long-life infrastructure investments such as transmission, substations, poles and wires. In addition, the Operating and Capital Budgets fund investments in various information technology projects, services and commodities needed to support system operations.

The proposed 2019 Budget is consistent with the financial policy adopted by the Board of Trustees in December 2015 to reduce the Authority's borrowing and interest cost and raise the Authority's credit ratings over five years. That policy established a fixed obligation coverage target of 1.45x for LIPA fixed obligation payments for 2019. Staff projects that the 2019 Budget will achieve a coverage ratio of 1.45x in 2019.

In addition, the Budget meets the Board's financial policy for borrowing, with new debt funding less than 64% of capital spending. For 2019, staff projects LIPA will fund 62% of the \$869 million Capital Budget from debt issues, inclusive of FEMA projects, achieving the Board's fiscal goal. Excluding the \$138.2 million of FEMA financed projects, staff forecasts 73% would be financed with debt. The 2019 Capital Budget includes a deferral of certain specified 2018 capital projects totaling \$56.1 million into 2019.

The monthly electric bill for the average residential customer is projected to be \$154.94 in 2019, which is \$3.67 per month or 2% below the 2018 budgeted level. The primary drivers of the decrease are lower Power Supply Costs and credits resulting from the Revenue Decoupling Mechanism. These decreases offset increases in infrastructure investments, storm restoration costs, and energy efficiency investments, as described in greater detail in the Budget.

Changes from the Proposed Budget

The 2019 Budget presented herein reflects minor adjustments to the Proposed Budget presented to the Trustees on November 14, 2018. Adjustments include (1) an update to capitalized lease costs that was offset by other adjustments, resulting in no change to total Delivery Revenue Requirements; and (2) an update to the Distributed Energy Resources rider (“DER”) totaling \$420,000 for Direct Current Fast Charging (“DCFC”) incentives for electric vehicles, consistent with the Consensus Proposal filed in the New York Department of Public Service’s electric vehicle proceeding subsequent to the submission of LIPA’s Proposed Budget.¹ The objective of the DCFC incentives is to spur investment in DCFC stations by mitigating the impact of demand charges on station owners during the next several years of low expected station utilization.

Power Supply Charge and Allocation of Intra-Year Power Supply Capacity Costs

In December 2015, the Trustees approved a regulatory asset to allow for a greater share of the recovery of certain fixed generation capacity costs in the Power Supply Charge (“PSC”) from customers during the summer months consistent with when the generation capacity is needed rather than recovering these fixed costs equally through the year. Staff believes this accurately reflects cost causation in electric rates. The December 2015 approval by the Trustees specified that the schedule of deferrals and amortization of such costs in future years would be presented in future budgets. There is no net impact on an annual basis from the reallocation of these costs within the year, with allocations by month from plus \$30 million to minus \$28.5 million, as shown in the table below.

	Reallocation of the Proposed Fixed Capacity Costs in the Power Supply Charge
January	(\$28,500,000)
February	(\$28,500,000)
March	(\$11,000,000)
April	(\$9,000,000)
May	(\$4,000,000)
June	\$11,000,000
July	\$30,000,000
August	\$30,000,000
September	\$22,000,000
October	(\$1,000,000)
November	(\$4,500,000)
December	(\$6,500,000)
Annual	\$0 Million

¹ Case No. 18-00561, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (consensus proposal filed November 21, 2018). In its recommendation on PSEG Long Island’s 2018 Utility 2.0 Plan, the Department of Public Service recommended adoption of DCFC incentives consistent with this proceeding.

The annual PSC is projected to decrease from \$1.877 billion in 2018 to \$1.793 billion in 2019 for a savings of \$84 million. The primary drivers of the decline include lower projected energy sales, lower commodity prices, reduced gas transportation costs, and reduced generation capacity payments. In addition to the cost of fuels consumed in generation and purchased power, the Authority's share of costs charged by the regional energy markets, payments to energy service companies, Zero Emission Credits associated with the adoption by the NYS Public Service Commission of the Clean Energy Standard, as well as other agreements, hedging, and renewable energy costs are included in the PSC.

LIPA staff also seeks authorization to implement a recommendation made by PSEG Long Island to book regulatory assets for "Unusual Events" that would cause volatility (at the level described in the following paragraph) in the PSC. An Unusual Event is defined to mean an unexpected or unpredictable occurrence outside the control of the utility which results in a significant increase or decrease in power supply cost as compared to the projected level of power supply costs used to establish the PSC in a month. Unusual Events include, among others: sustained abnormal extremes in weather (e.g. a polar vortex); a major disruption in fuel supply; or the extended forced outage of a major electric facility (e.g., a transmission cable or power plant); and a change in law, regulation, or standard contract provision.

As proposed, a regulatory asset may be needed if, as a result of the occurrence of an Unusual Event, any month's Deferred Fuel Balance and/or current month's projected fuel costs rise to a level that would result in a change of more than 0.50 ¢/kWh in the immediately succeeding month's PSC as compared to the current month's PSC. The recovery of that portion of the deferred fuel balance or current month's projected recovery position attributable to the Unusual Event may be amortized so as to limit the month-over-month change in the PSC to no more than 0.50 ¢/kWh. In no event however shall the amortization period exceed four months.

Operating Expense

Total operating expenses are projected to increase from \$719.8 million in 2018 to \$765.2 million in 2019 for an increase of \$45.4 million. Operating Expenses include PSEG Long Island Operating Expenses, PSEG Long Island Managed Expenses and LIPA Operating Expenses.

PSEG Long Island Operating Expenses include: T&D, Customer Service, Power Markets, Renewable Energy programs and costs associated with the annual Utility 2.0 Plan. PSEG Long Island Operating Expenses must remain within 102% of amounts budgeted for PSEG Long Island to receive its incentive compensation.

PSEG Long Island Managed Expenses are costs managed by PSEG Long Island, but not measured for incentive compensation as some of these expenses are not within their control. These include storm preparation and restoration, depreciation, uncollectible receivables and PILOTs.

LIPA Operating Expenses include PSEG Long Island's management fee, Authority staff salaries and professional consultant fees.

The increase in expenses is associated with a higher budget for storm related costs, the addition of new and expanded Utility 2.0 programs, including funding associated with Advanced Metering Infrastructure (AMI) meters, and a carryover of \$0.7 million from 2018 to 2019 of funds associated with the 2018 Utility 2.0 Super Saver program.

Accounting Treatment Related to the Resolution of Superstorm Sandy Estimates

Included in the LIPA 2019 Operating Budget is the reduced amortization expense related to the resolution of Superstorm Sandy costs. In 2012, Superstorm Sandy caused costly and extensive damage to LIPA's transmission and distribution system. LIPA recognized the cost of such damage based on best available estimates in accordance with generally accepted accounting principles. Actual costs, including proper supporting documentation, were substantially delayed due to the inability of LIPA's former service provider to produce bills due to the implementation of a new accounting system.

During 2018, LIPA paid its final invoice related to these delayed billings. The initial estimates were higher than actual costs. Rather than lower the amount recognized by LIPA six years ago and distort current results, the Authority is afforded regulatory accounting treatment under GASB No. 62 and is, therefore, recommending netting this one-time adjustment of \$42 million against an existing regulatory asset consistent with actions approved by the Board in the past. This action will reduce the existing regulatory asset amortization by approximately \$6.0 million annually.

As LIPA follows the Public Power Model, this transaction does not impact the Authority's expenditures or the level of electric rates but does provide a less complex and more informative view of LIPA's net position and going forward financial condition to stakeholders, rating agencies, and investors. This accounting treatment is a preferred treatment for LIPA as its delivery rates are set to produce cash flows sufficient to cover debt service obligations rather than a traditional rate base/rate of return formulation of revenue requirements.

PILOTs, Taxes and Other Assessments

PILOTs, Taxes and Other Assessments are projected to increase from \$544.8 million in 2018 to \$546.3 million in 2019. PILOTs are both revenue-based and property-based. Property-based PILOTs are on Authority-owned properties and the LIPA Reform Act established a 2% annual cap on increases. In addition, the Authority incurs real property taxes associated with generating assets under contract through the National Grid Power Supply Agreement, among other agreements. The Authority continues to challenge these property taxes which are significantly over-assessed.

Annual Budget and Rate Updates

Under the New York Public Authorities Law as amended by the LIPA Reform Act (P.A.L. § 1020 et seq.), the Authority and PSEG Long Island are required to submit a proposed rate increase to the New York Department of Public Service (the "DPS") for review if it would increase the rates and charges by an amount that would increase the Authority's annual revenues by more than 2.5% of the prior year's total annual revenues. The proposed budget and associated rate adjustments would

increase the Authority's 2019 revenues by less than this threshold.

In March 2015, the Authority adopted a "Revenue Decoupling Mechanism," which functions by comparing actual revenues with revenues authorized in the approved budget, and crediting (or collecting) any differences due to (or from) customers in the following year. In addition to recovering the variance between the prior year's budgeted and actual revenues, the RDM also recovers an estimate of such variance for the coming year (the "forward-looking component"). The forward-looking component is estimated based on the prior year's actual variance. This method produces reasonable estimates if the variance between budgeted and actual revenues remains similar from year to year in a multi-year sales forecast, such as the one adopted as part of the Authority's Three-Year Rate Case for 2016, 2017 and 2018.

The Authority used its most recent forecast of electricity sales to propose rates for 2019 sufficient to achieve the Authority's revenue requirements. Using an updated sales forecast for 2019 should result in a smaller variance because more recent information is available (producing a more accurate forecast). As a result, the forward-looking component of the RDM is not needed in any year in which an updated sales forecast is used to calculate rates and failure to recognize this could result in greater than necessary RDM revenue collection in the upcoming year. For this reason, Staff recommends that the RDM be modified such that the forward-looking component may be suspended in any year in which an updated sales forecast is used to calculate rates.

2019 Utility 2.0 Plan

The 2019 Proposed Budget includes \$69.7 million in Capital funding and \$16.4 million in Operating funding for Utility 2.0 initiatives. The Utility 2.0 plan is consistent with the DPS recommendation (attached as **Exhibit "C"**). The Utility 2.0 Program provides for full deployment of AMI meters, an expanded Super Savers program, a new Behind-the-Meter Storage program, and a new electric vehicle charging station incentive program.

Energy and Nature Center

The proposed Capital Budget includes \$9.0 million for the planning, design and construction of a new Energy and Nature Center at Jones Beach pursuant to a Memorandum of Agreement between LIPA and the New York State Office of Parks and Recreation and Historic Preservation ("Parks"). The Energy and Nature Center ("Center") at Jones Beach will be a public-private partnership that LIPA and Parks will jointly fund. The partnership will jointly oversee the design, construction and operations of the Center, in addition to engaging in public outreach during all phases of planning, design and construction.

The Energy and Nature Center at Jones Beach will set an example of sustainable and resilient design, and through a variety of hands-on exhibits and programs, visitors to the Center will gain an understanding of Long Island's various ecosystems and learn how to use energy wisely and create a more resilient and sustainable future. The Center will be an interactive facility for visitors of all ages to become stewards of the environment and smart energy consumers with construction to begin later in 2019 and opening late-2020 early 2021.

Information Technology

LIPA's proposed Operating and Capital Budgets include \$8.4 million for Information Technology ("IT") professional services and commodities that are expected to be procured using contracts negotiated by the New York State Office of the General Services ("NYS-OGS") and Federal Supply Schedules (General Service Administration or "GSA").

IT professional services include management support and expert assistance outside the scopes of service for LIPA's current IT consulting services contracts. These services would be billed on a fixed hourly labor rate or at a fixed-cost, at or below the rates negotiated by the NYS-OGS or the GSA, as applicable, on an as-needed basis to support various IT system implementation initiatives as well as operational and oversight functions. Over the next three years, such anticipated professional services include system design and architecture in order to support LIPA IT infrastructure upgrades, a data portability roadmap and Intranet initiatives, system integration and implementation of an IT helpdesk, inventory management, a new enterprise resource planning system ("ERP"), Cloud migration, cybersecurity planning and implementation, IT strategic planning, business process improvement initiatives related to various IT systems implementations, quality assurance of various IT initiatives within LIPA and independent verification and validation of IT system implementations managed by PSEG Long Island.

Commodities to be procured include hardware, software licenses, software/cloud subscription, system hosting, telephony, telecom, audiovisual support and services on an as-needed basis in the ordinary course of business and continued maintenance of the existing hardware and software.

Amendment of the 2018 Operating and Capital Budgets

PSEG Long Island's 2018 approved Operating Budget is being reduced by \$0.7 million to account for the carryover of funds related to the Utility 2.0 Super Saver program from 2018 to 2019.

PSEG Long Island is reducing its approved 2018 Capital Budget by \$58.6 million. This reflects the carryover of \$56.1 million in Capital projects from 2018 to 2019, including \$41.8 million in Load Growth projects such as the Ruland Road New 69 KV Circuit and the Canal to Southampton New 69 KV Transmission Circuit. In addition, 2018 Utility 2.0 funding is reduced by \$2.5 million, to reflect a correction to the budget of \$4.8 million and accelerated meter deployment of \$2.3 million.

Public Comment on the 2019 Operating and Capital Budgets

The Authority held two public comment sessions on the 2019 Budget, one in Nassau County and one in Suffolk County, both on November 16, 2018. No public comments were received at the public hearings.

The Authority also accepted written and emailed comments. Three comments were received from individual customers. Two customers had read a November newspaper article on the 2019 Budget and wrote in opposition to any increase in delivery rates. One customer sought further information on the Budget than was provided in the article. The requested information was provided by Authority staff. This customer also expressed opposition to any increase in delivery rates.

The DPS received the Authority's Annual Budget and Rate Update filing and Utility 2.0 filing as described above.

Recommendation

Based upon the foregoing, I recommend approval of the above requested action by adoption of a resolution in the form of the draft resolution attached hereto.

Attachments

<u>Exhibit "A"</u>	Resolution
<u>Exhibit "B"</u>	Proposed 2019 Operating and Capital Budgets
<u>Exhibit "C"</u>	DPS Utility 2.0 Recommendation
<u>Exhibit "D"</u>	Tariff redline reflecting rate adjustments and RDM modification

**RECOMMENDING APPROVAL OF THE 2019 OPERATING AND CAPITAL BUDGETS
AND AMENDMENT OF THE 2018 BUDGETS**

WHEREAS, the Long Island Power Authority (“Authority”), through its wholly owned subsidiary, LIPA, owns the electric transmission and distribution system serving the counties of Nassau and Suffolk and a small portion of the County of Queens known as the Rockaways; and

WHEREAS, the Board of Trustees is required to approve annual budgets for the operations of the Authority and for capital improvements; and

WHEREAS, the proposed budget incorporates Operating and Capital budgets for the operation and maintenance of the transmission and distribution system, customer services, business services and energy efficiency and renewable energy programs which are predicated on improving storm response and restoration, customer satisfaction, and reliability and storm hardening; and

WHEREAS, under the New York Public Authorities Law as amended by the LIPA Reform Act (P.A.L. § 1020 et seq.), the Authority and PSEG Long Island are required to submit a proposed rate increase to the New York Department of Public Service for review if it would increase the rates and charges by an amount that would increase the Authority’s annual revenues by more than 2.5% of the prior year’s total annual revenues. The proposed budget and associated rate adjustments would increase the Authority’s 2019 revenues by less than this threshold. Therefore, the proposed budget contains Rate updates consistent with the Authority’s Mission, Board Policies, and the LIPA Reform Act; and

WHEREAS, the Authority released its proposed 2019 Operating and Capital Budgets on November 14, 2018 and held two public comment sessions on November 16, 2018; and

WHEREAS, the memorandum accompanying this resolution includes a schedule of deferrals and amortizations of certain generation capacity costs within the months of the year to affect the more accurate reflection of cost causation in electric rates within each month of the year; and

WHEREAS, the proposed budget includes \$9 million for the planning, design and construction of a new energy and nature education center at Jones Beach in partnership with the NYS Department of Parks and Recreation, which will require the Chief Executive Officer or his designee(s) to execute the Memorandum of Agreement as described in the accompanying Memorandum; and

NOW, THEREFORE, BE IT RESOLVED, that consistent with the accompanying memorandum, the Finance and Audit Committee (the “Committee”) of the Board of Trustees hereby recommends approval of the proposed 2019 Operating and Capital Budgets and associated rate and RDM adjustments, which are attached hereto; and

BE IT FURTHER RESOLVED, that the the Committee hereby recommends that the Authority amend its approved 2018 Capital Budget to reduce expenditures by \$58.6 million to defer these expenditures to 2019 and correct the Utility 2.0 funding; and

BE IT FURTHER RESOLVED, that the Committee hereby recommends that that the Authority amends its approved 2018 Operating Budget to reduce by \$0.7 million to defer these expenditures to 2019; and

BE IT FURTHER RESOLVED, that the Committee hereby recommends that that the Authority establish a regulatory asset as described in the accompanying memorandum for Unusual Events that would result in a change of more than 0.50 ¢/kWh in the immediately succeeding month's PSC as compared to the current month's PSC allowing for recovery over a period not to exceed four months; and

BE IT FURTHER RESOLVED, that the Committee hereby recommends that the Authority transfer accounting impacts due to the resolution of Superstorm Sandy estimates against a regulatory asset and reduce its annual amortization over the remaining life; and

BE IT FURTHER RESOLVED, that the Committee hereby recommends that that the Authority finance the requirements of the 2019 and 2020 Capital Budgets, as adjusted from time to time, through a combination of internally-generated funds and the issuance of tax-exempt or taxable debt of the Authority and authorizes the Officers of the Authority to evidence such intent by appropriate certifications; and

BE IT FURTHER RESOLVED, that the Committee hereby recommends that the Chief Executive Officer and his designees be authorized to carry out all actions deemed necessary or convenient to implement this resolution.

Dated: December 19, 2018

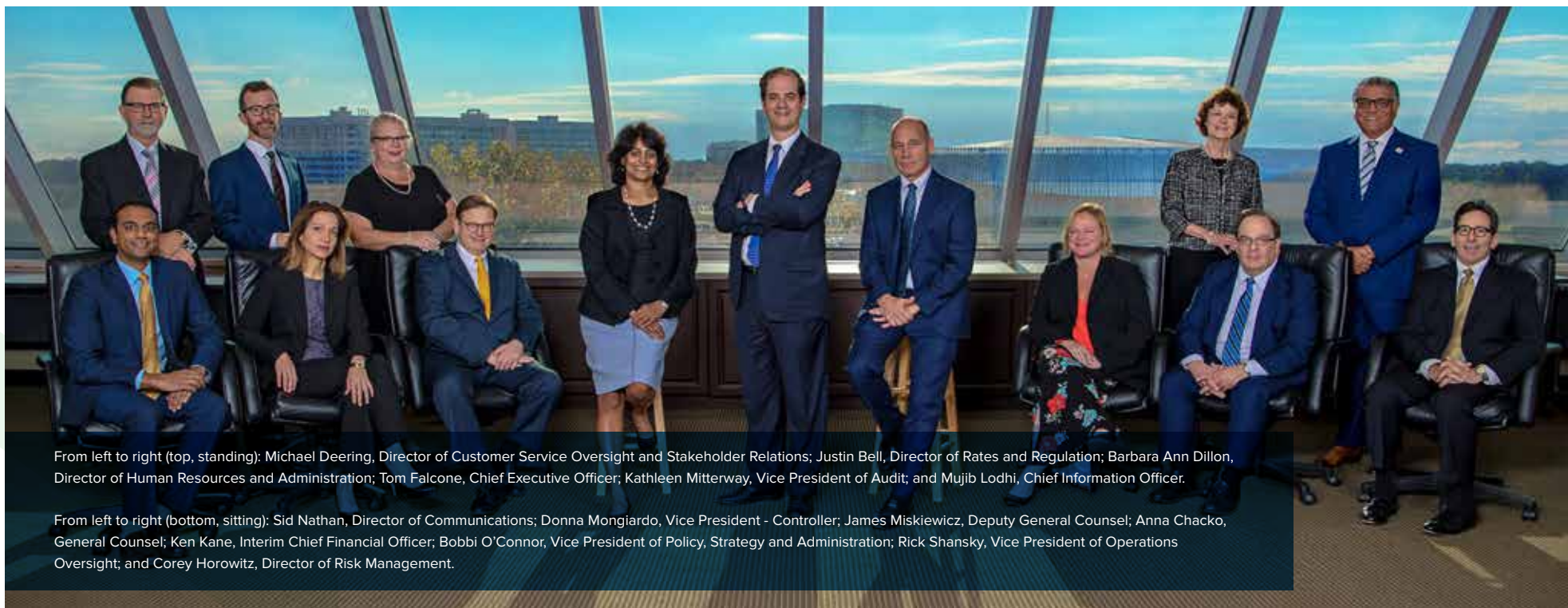


LONG ISLAND POWER AUTHORITY

POWERING LONG ISLAND'S **CLEAN, RELIABLE,** AND **AFFORDABLE** ENERGY FUTURE



2019 BUDGET



From left to right (top, standing): Michael Deering, Director of Customer Service Oversight and Stakeholder Relations; Justin Bell, Director of Rates and Regulation; Barbara Ann Dillon, Director of Human Resources and Administration; Tom Falcone, Chief Executive Officer; Kathleen Mitterway, Vice President of Audit; and Mujib Lodhi, Chief Information Officer.

From left to right (bottom, sitting): Sid Nathan, Director of Communications; Donna Mongiardo, Vice President - Controller; James Miskiewicz, Deputy General Counsel; Anna Chacko, General Counsel; Ken Kane, Interim Chief Financial Officer; Bobbi O'Connor, Vice President of Policy, Strategy and Administration; Rick Shansky, Vice President of Operations Oversight; and Corey Horowitz, Director of Risk Management.

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Executive Management

- | | |
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| > Rick Shansky
Vice President of
Operations Oversight | > Mujib Lodhi
Chief Information Officer |

> CUSTOMERS

Residential:
1,008,486
Commercial:
120,950

> 2018 PEAK

DEMAND
5,412 MW

> GENERATING

CAPACITY
5,762 MW

> ENERGY
REQUIREMENTS
20,195,715 MWh

> TRANSMISSION
SYSTEM
1,360 miles

> DISTRIBUTION
SYSTEM
9,000 miles overhead
5,000 miles underground
189,000 transformers

SUBSTATIONS
181 Substations
30 Transmission
151 Distribution

> 2019 BUDGET:
Operating
\$3,598,846,000
Capital:
\$868,829,000

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SECTION II

LIPA'S 2019 BUDGET

Long Island is home to New York's three largest utility-scale solar fields. Pictured here is the Long Island Solar Farm at Brookhaven National Laboratory.

> MISSION STATEMENT

LIPA is a not-for-profit public utility with a mission to enable clean, reliable, and affordable electric service for our customers on Long Island and the Rockaways.

PUBLIC POWER BENEFITS LONG ISLAND



Your local public power utility is community owned and governed by a Board of Long Island residents.

LIPA is a not-for-profit electric utility that does not pay dividends to shareholders or corporate income taxes on profits. LIPA invests all of your dollars in a more reliable Long Island electric grid.

We contract with PSEG Long Island to manage our electric grid under a 12-year agreement. By using a public-private business model, we combine local control, public ownership, and a lower cost structure with the customer service and industry experience of a nationally recognized neighboring utility. In fact, Long Island's hometown electric utility is the most improved utility in the nation for residential customer satisfaction, according to J.D. Power.

Your local public power utility has access to government grants and tax-exempt financing. With Governor Andrew M. Cuomo's help, we secured the largest utility infrastructure investment in Long Island's history—a \$730 million federally funded storm hardening program. From Merrick to Montauk and Bellmore to Blue Point, our investments are improving service for all 1.1 million customers.

Your local public power utility is also a powerful economic engine for Long Island. LIPA and PSEG Long Island support hundreds of local companies by purchasing over \$120 million of goods and services each year from Long Island businesses. In fact, there are over 16,000 Long Island jobs connected to PSEG Long Island's presence.

We are proud of what LIPA and PSEG Long Island have accomplished together.

PSEG LONG ISLAND in the **COMMUNITY**

There is more than one way to power the local economy. PSEG Long Island's customers are benefiting from new economic development programs that assist small businesses and revitalize downtown areas. The Main Street Revitalization Program and Vacant Space Revival Program are breathing new life into struggling business districts. Boosting the economic vitality of our downtowns is part of PSEG Long Island's core commitment to give back to the communities it serves.

There is also more than one way to invest in a community. PSEG Long Island supports charities, and actively volunteers at local community events such as the March of Dimes, Marcum Workplace Challenge, and Strides Against Breast Cancer. PSEG Long Island also provides educational programs on energy efficiency to 200 schools across Long Island and the Rockaways, reaching over 80,000 students each year.



I wanted a change from my current job so I saved money and decided to start my own small business. PSEG Long Island's Main Street Revitalization Program helped me as a new business owner manage unexpected expenses and freed up a lot of my capital and cash flow. It was amazing to sit back at the end of my first day and say "I did it." It was really amazing."

— Mika Rose, My Home Favorites

BUDGET MESSAGE

Dear Customers and Stakeholders,

LIPA and PSEG Long Island established goals for the first five years of our public-private partnership – the most important of which was to provide more value for our customers' dollars.

With 2018 coming to an end, we have completed the first five years together, and it is a good time to both reflect on what we have accomplished and to tell you what we have planned for the next five years.



Thomas Falcone
Chief Executive Officer

OUR FOCUS is on CUSTOMER VALUE

In last year's budget message, we described the significant components of customer satisfaction for an electric utility:

- > **Power Quality and Reliability**, including investments that avoid outages and timely and accurate communications about service restoration;
- > **Customer Service**, including friendly, knowledgeable employees, who can resolve customer issues the first time;
- > **Corporate Citizenship**, including environmental stewardship and community involvement;
- > **Reasonable Rates**, including stable electric bills and pricing options that meet diverse customer needs; and
- > **Helpful Billing and Payment Processes**, including bills and websites with useful information and convenient methods to pay bills.

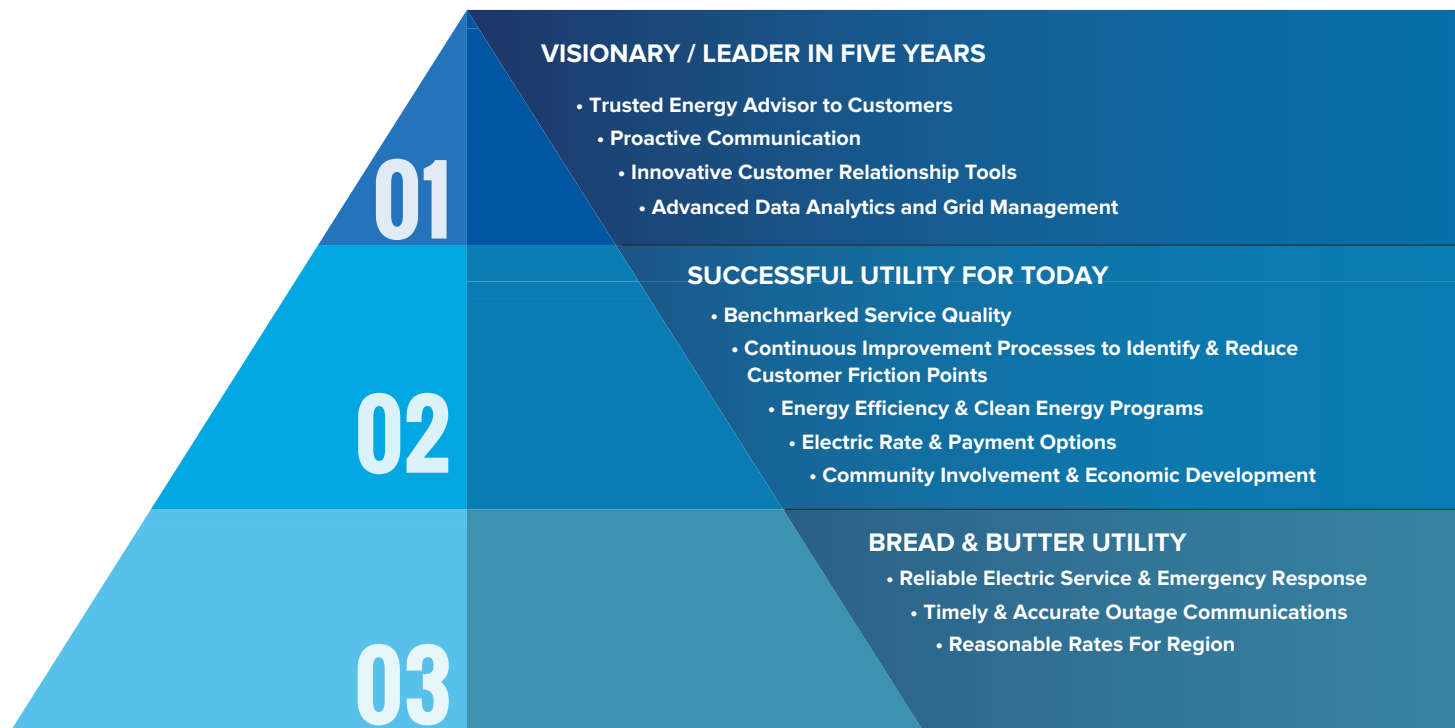
We also described how LIPA's Board of Trustees sets high goals for our organization based on this feedback from our customers. These goals guide our budgetary

tradeoffs between cost and service in meeting our customers' expectations. Our Board's policies are described on our website, and the actions required to meet our customers' expectations are summarized in Figure 1.

Historically, LIPA had been focused on "bread and butter" utility operations. Our past budgets prioritized system reliability, within the constraints of keeping delivery rates and debt flat. Within those constraints, there were less than adequate funds to leverage technology or enhance customer service and reliability.

Customers compare and expect the interactions they have with their electric utility to be on par with their other business interactions. We simply were not investing sufficiently to meet those expectations, let alone to be considered among the successful companies in our industry.

FIGURE 1



PRICE IS WHAT YOU PAY, VALUE IS WHAT YOU GET

In 2014, we changed our focus to ensure that your needs are our priorities. I would like to summarize how LIPA and PSEG Long Island have performed since that change.

Figure 2 shows our average residential customer's electric bill in 2013 and 2018. Electric rates remain below the rate of inflation, while other goods and services steadily increase.

The average bill has increased from **\$151.64 per month in 2013 to \$158.61 per month in 2018, a change of five percent over five years, or half the rate of inflation.** Part of that is due to moderate fuel and power costs, but it is also a direct result of the savings initiatives described on page 20, which have reduced 2019 customer bills by 17 percent.

FIGURE 2

Costs of Goods and Services Rise Over Last Five Years while Customer Bills Remain Below the Rate Inflation

Source: U.S. Bureau of Labor Statistics

Medical Care Services



▲ **13.83%**

Housing



▲ **16.54%**

Transportation Services



▲ **14.56%**

Food



▲ **6.82%**

Electric Bill



▲ **5%**

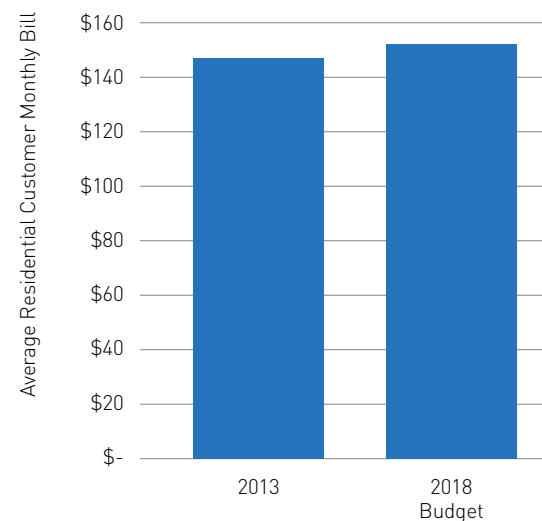
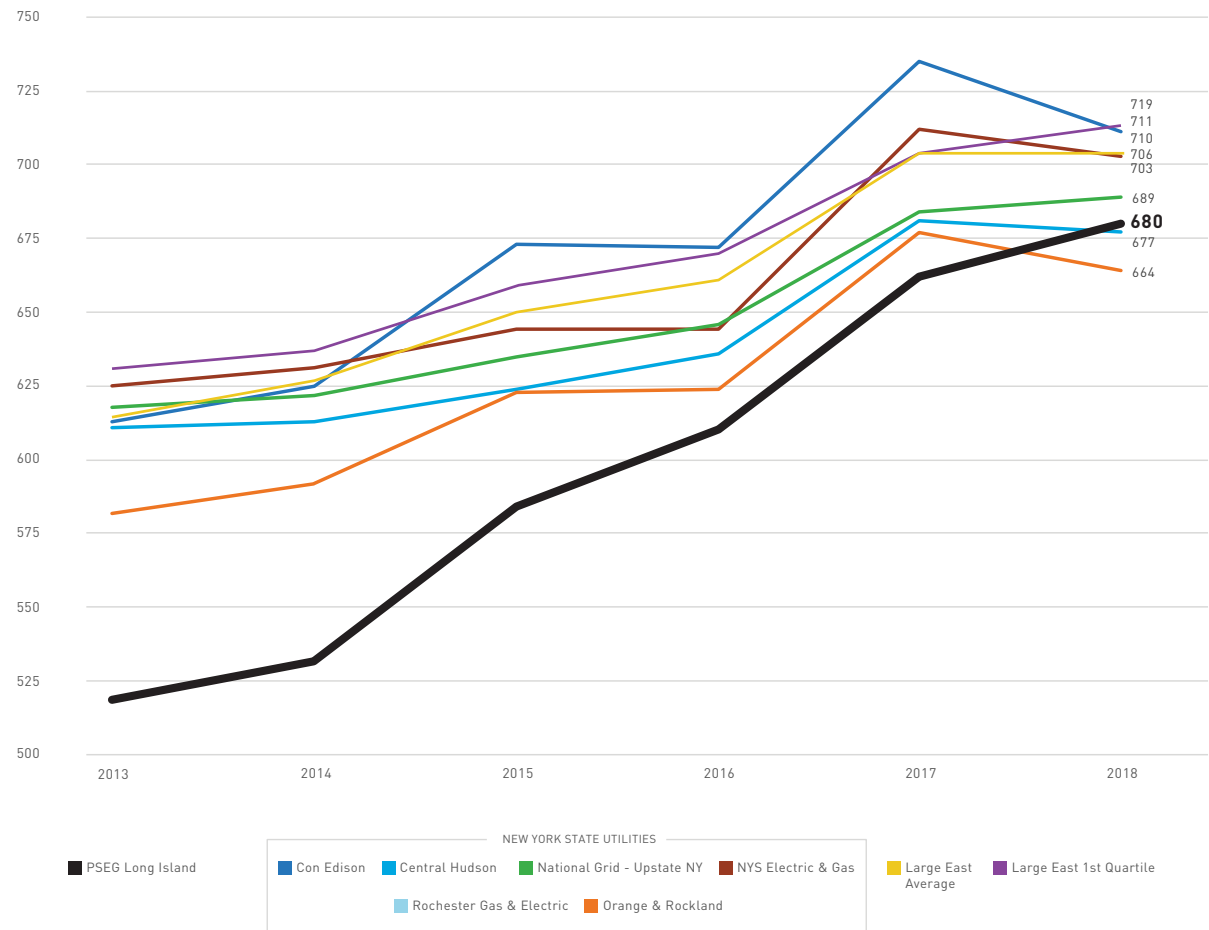


Figure 3 shows that while average bills have been roughly flat over the past five years, **customer satisfaction, as measured by the J.D. Power Residential Customer Satisfaction Study, has increased by more than 161 points.** Price is what you pay, and value is what you get. With bills roughly flat, improving customer satisfaction is the result of customers indicating they are receiving more value for their money.

How significant is this increase in customer satisfaction? LIPA was not just last in customer satisfaction among large, Northeast utilities in 2013, but last in the country -- and by a wide margin. In fact, LIPA was consistently among the lowest ranked utilities in the country for customer satisfaction since the survey began in 1999.

FIGURE 3**J.D. Power Residential Customer Satisfaction - New York State and Large East Utilities**

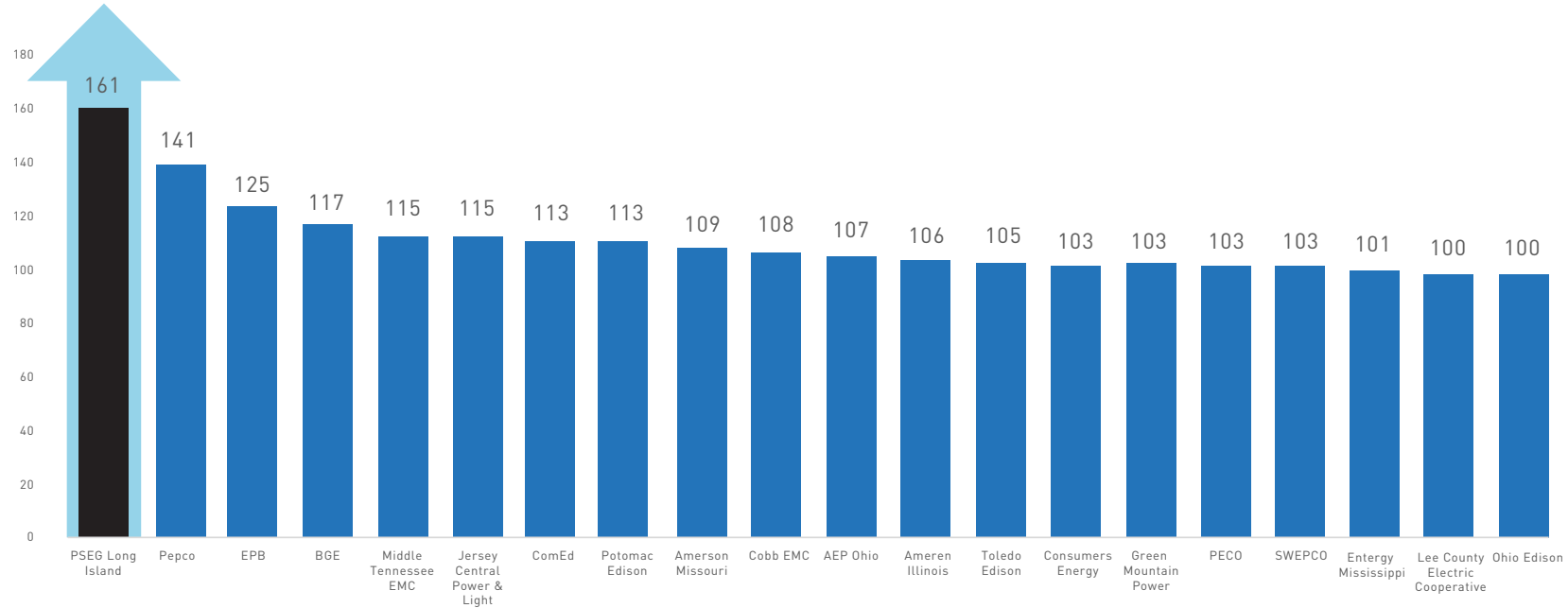
PSEG Long Island has improved customer satisfaction by 161 points since 2013.



As shown in Figure 4, **PSEG Long Island is now the most improved utility in the country for customer satisfaction over the past five years.** Of the 138 largest electric utilities in the United States, which collectively serve over 99 million customers, PSEG Long Island is among only 20 utilities to increase their score over 100 points.

FIGURE 4**PSEG Long Island Ranked Most Improved Utility in Nation**

PSEG Long Island has improved at a rate 55 percent greater than the average rate of improvement of the other 19 most improved electric utilities in the country over the period 2013-2018; and twice the rate of improvement of the average electric utility in the nation (national average = 81).



There is always more to do, but we are providing a better product, and our customers are noticing. I will now discuss some of our major initiatives, both in the past five years and for the next five.

IMPROVING CUSTOMER SERVICE

PSEG Long Island serves customers much better than LIPA and its prior service provider did five years ago, across a broad range of metrics. In 2013, LIPA and PSEG Long Island set improvement goals for key measures of customer service. Figure 5 shows how significantly **PSEG Long Island has improved performance on customer service measures** in areas such as:

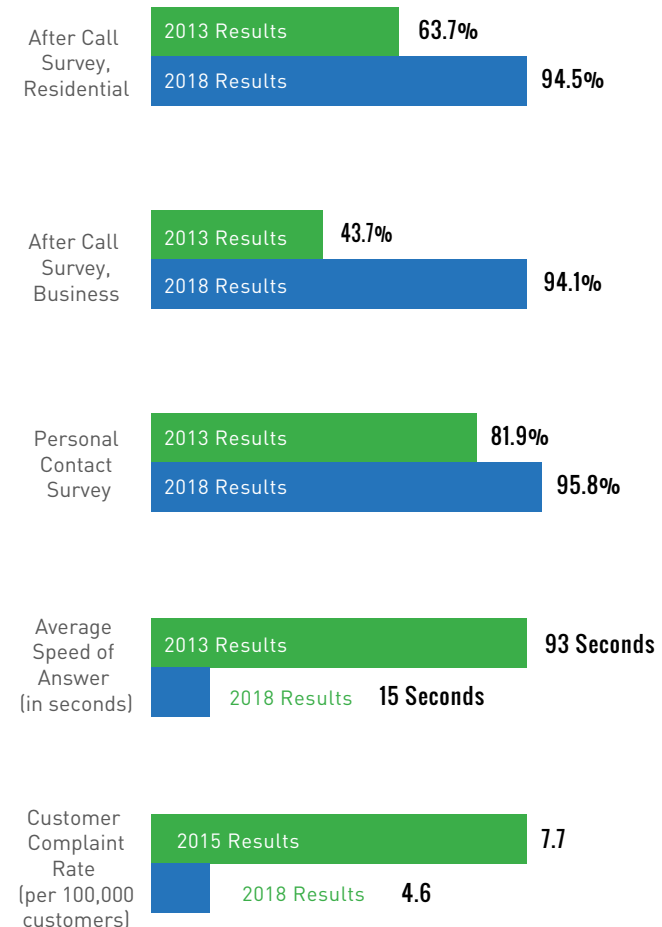
- > **After-call satisfaction surveys** of residential and business customers;
- > **Surveys of customer satisfaction** after a personal interaction with the utility, including at home, one of our customer offices, with one of our large account representatives, or on our energy efficiency information line; and
- > **Customer complaints** filed with the New York Department of Public Service.

These improvements required changes in processes to eliminate friction points for customers, investments in information technology and customer-facing systems, and improvements in employee training programs.

The 2019 budget invests in our customer service and community involvement initiatives for the next five years.

FIGURE 5

PSEG Long Island Customer Service Improvements



2019 Budget Invests In Customer Service and Community Involvement Initiatives for the Next Five Years

Customer Service



- > Deploying smart meters to all customers by the end of 2022, transforming the customer experience with information and tools to manage energy usage;
- > Integrating industry-leading customer relationship software to deliver a unique and personalized customer experience;
- > Modernizing the customer experience, including more pro-active communication with customers about their usage and outages, new convenient payment options, and improved power quality measured at each customers' home or business;
- > New electric rate pricing plans that better meet customers' lifestyles and needs, such as smart home rates, green rates, and a good neighbor rate; and
- > Launching a new mobile app to enhance the customer experience through features such as outage tracking, bill payment, and outage and energy alerts.



Smart Meters will modernize the customer experience and will be fully deployed by 2022

Community Involvement



Visit YouTube @PSEGLongIsland

Vacant Space Revival Program helps small business and communities thrive



- > Continued community involvement, such as PSEG Long Island's Main Street and Vacant Space Revitalization Programs to help small businesses open their doors and downtown business districts remain vibrant on Long Island and in the Rockaways;

- > Building a state-of-the-art Energy and Nature Education Center at Jones Beach State Park to encourage visitors of all ages to become good stewards of the environment and smart energy consumers.



MEETING THE STATE'S AGGRESSIVE CLEAN ENERGY GOALS

Your customer owned local electric utility plays an important part in reducing emissions and meeting the clean energy needs of Long Island and the Rockaways.

New York has nation-leading clean energy policies, including:

- > Increasing renewables to 50 percent of New York's electricity by 2030;
- > Installing 2,400 megawatts of offshore wind by 2030 – enough to power 1.25 million homes;
- > Deploying 1,500 megawatts of storage by 2025; and
- > Decreasing greenhouse gas emissions from all sources by 40 percent by 2030 and 80 percent by 2050.

In each area, LIPA and PSEG Long Island have been leading the way in meeting the state's goals. Figure 6 shows a few of our initiatives, including New York's:

- > First offshore wind project, the 130 megawatt South Fork Wind Farm¹;
- > Three largest utility-scale solar farms, totaling 92 megawatts²;
- > Largest commitment to utility scale storage, with 80 megawatt-hours deployed;

- > Largest commitment to clean fuel cell technology, over 40 megawatts;
- > Most vibrant residential solar program, with over 44,000 customers; and
- > Largest energy efficiency program as measured by load reduction, reducing emissions and helping customer save money on their electric bills.

FIGURE 6

LIPA and PSEG Long Island's Clean Energy Accomplishments



¹ In November 2018, LIPA upgraded the South Fork Wind Farm from 90 to 130 megawatts to take advantage of the next generation of offshore wind turbines. The project will have the same 15-turbine footprint, but the larger turbines will deliver more clean energy at a lower cost.

² Utility-scale solar programs and projects exceed 173 megawatts of operational and contracted resources and an additional 77 megawatts of selected resources.

LIPA has invested more than \$1.4 billion in energy efficiency and clean energy resources over the last ten years, reducing Long Island's energy peak by more than 585 megawatts. Our continued investment will reduce carbon emissions on Long Island by 276,359 tons in 2019 and 3,559,833 tons by 2030, the equivalent of 286,069 average Long Island homes.

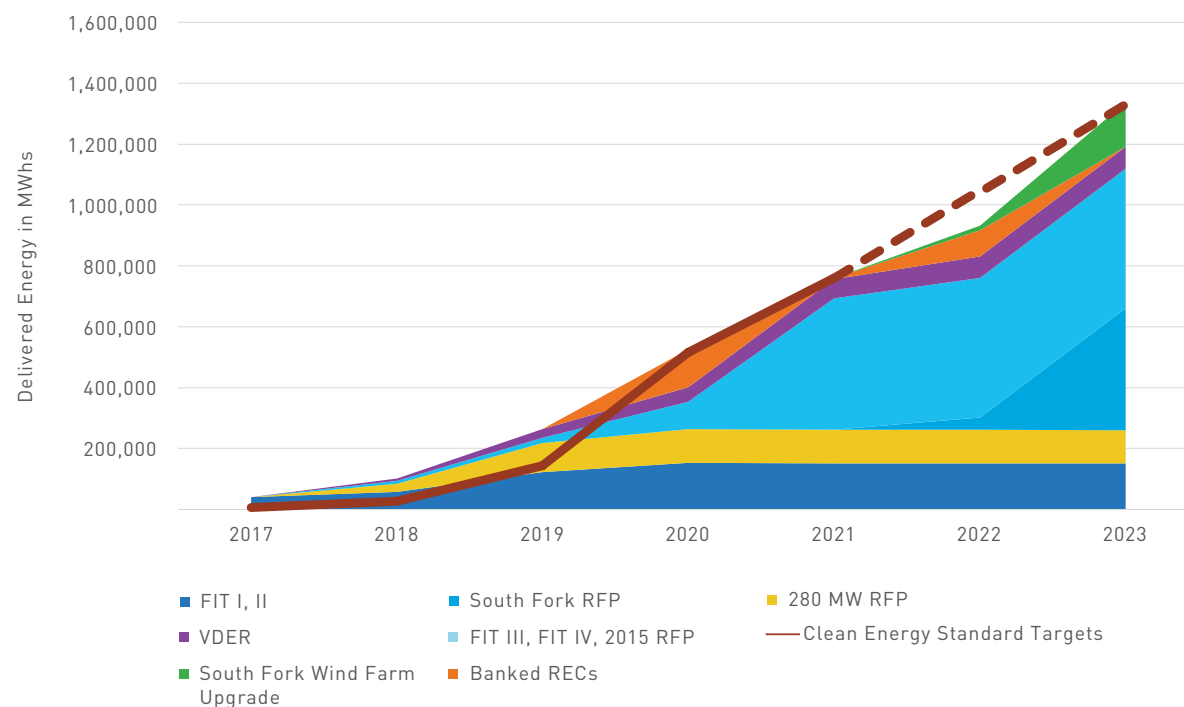
New clean energy programs for 2019 include:

- > Integrating a **new utility-scale storage program** to cost-effectively defer the need to build new distribution substations, while enhancing clean energy storage capacity;
- > Offering a **residential and commercial customer storage program** to provide an incentive to third-party aggregators who can use behind-the-meter storage to provide load relief to the electric grid on peak days; and
- > Promoting programs to **electrify transportation**, with the introduction of residential charger rebates, a residential Smart Charging discount for customers who charge their electric vehicle off-peak, and an incentive to encourage deployment of more electric vehicle fast charging stations on Long Island.³

With our existing and planned programs, **LIPA and PSEG Long Island are on target to meet the state's aggressive energy efficiency and clean energy standard goals**, as shown in Figure 7.

FIGURE 7

Clean Energy Standard Resources Coming Online are Sufficient to Meet Targets Through 2023



³ The electric vehicle fast charging incentive program will be designed during 2019 in coordination with a state-wide initiative.

MAINTAINING HIGH ELECTRIC SERVICE RELIABILITY

In 2013, LIPA and PSEG Long Island committed to maintaining electric grid reliability benchmarked to among the top 25 percent of peer utilities in the Northeast region. Several factors go into sustaining a reliable overhead utility, including system design, maintenance programs, and the level

of capital investment. Actions taken to improve reliability can take several years to become evident to customers. To paraphrase one utility veteran, if you are sitting in the shade today, it is because someone planted a tree a long time ago.

To meet our commitment to reliable electric service, LIPA and PSEG Long

Island have taken several actions over the past five years, including:

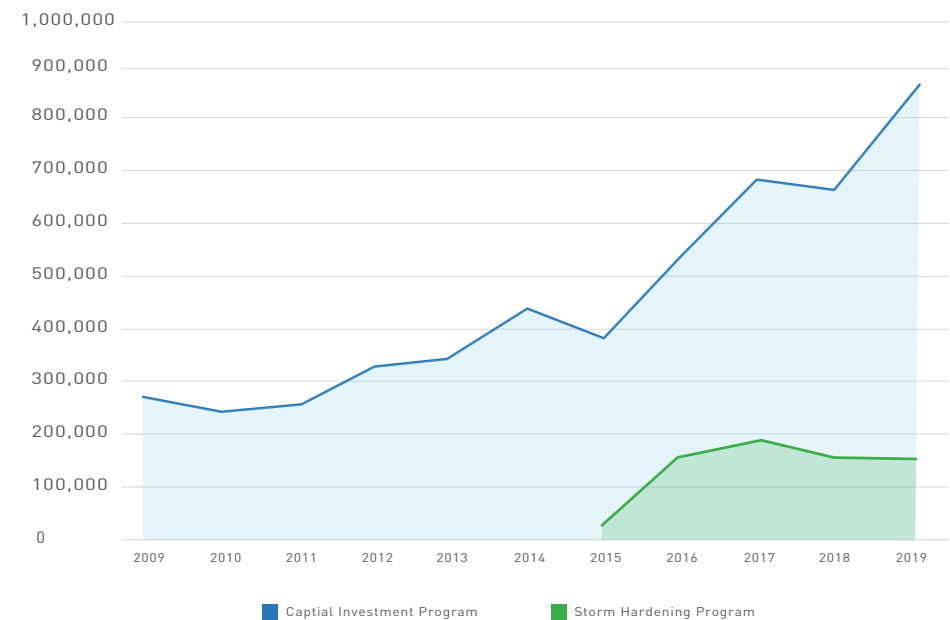
- > **Increasing the level of funding available to maintain the electric grid.** For example, in 2016 PSEG Long Island implemented a four-year tree trim cycle, replacing an older program with a cycle of six to seven years that left some trees untouched even longer. Pole inspection and maintenance programs were also enhanced, along with capital programs that target reliability;
- > **Implementing a \$730 million program to harden 1,000 miles of Long Island's electric circuits, raise ten at-risk substations above projected flood levels, and add nearly 900 new automated switches** that allow service interruptions to be isolated and minimized. Importantly, LIPA secured a federal grant to fund 90 percent of the cost of the storm hardening program – a benefit only available to publicly-owned utilities like the Authority; and
- > **Establishing a standard for reliability for each customer,** to ensure that customers with worse than average electric service are prioritized in our programs to maintain and improve the electric grid.

To paraphrase one utility veteran, if you are sitting in the shade today, it is because someone planted a tree a long time ago.

Figure 8 illustrates the level of system investment since 2009. LIPA averaged approximately \$300 million per year of capital expenditures over the five-year period from 2009 to 2013. **Since 2013, LIPA's annual spending on infrastructure has more than doubled, reaching \$869 million in 2019.**

FIGURE 8

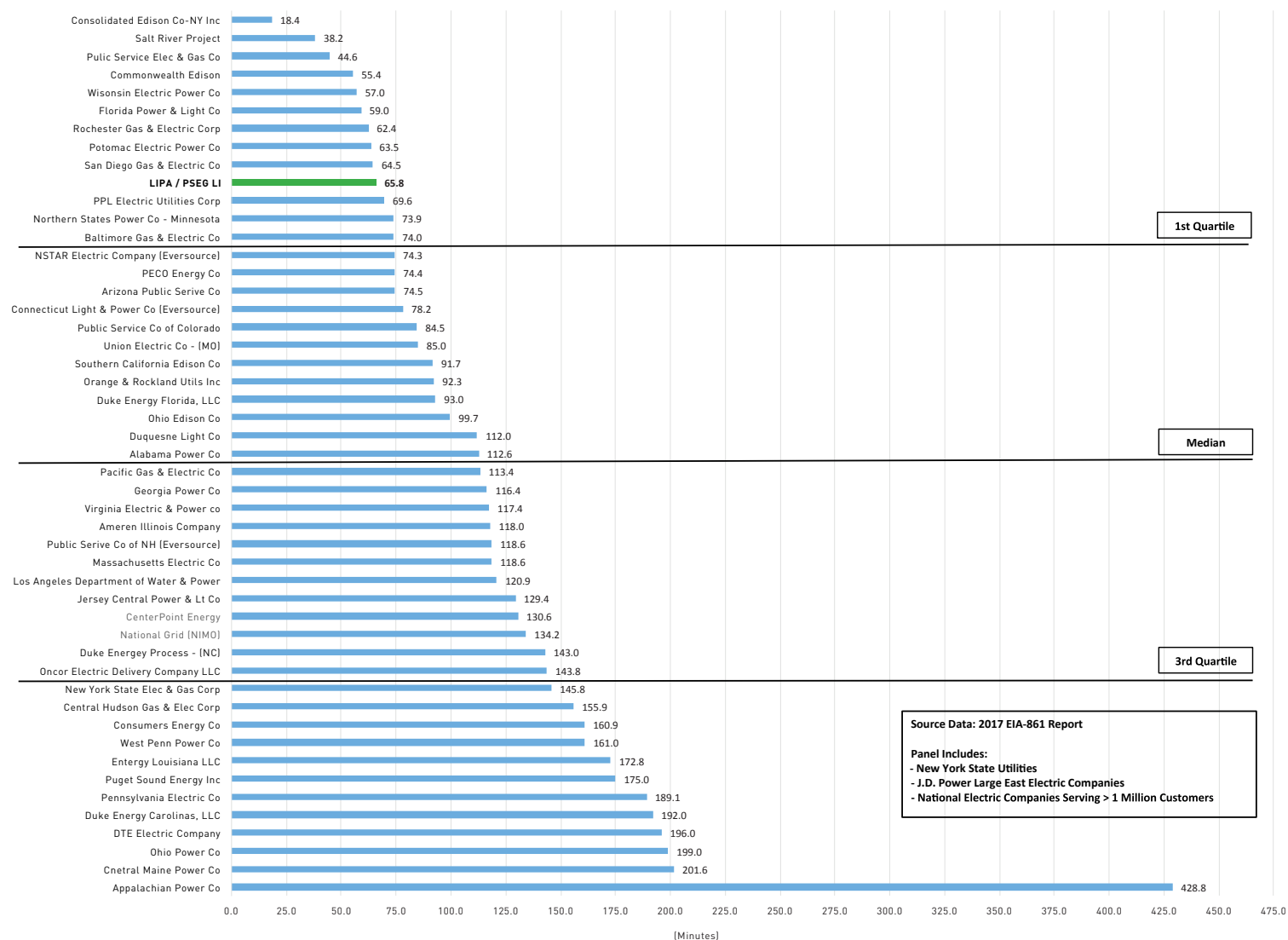
LIPA and PSEG Long Island Are Investing Record Funds in Electric Grid Reliability and Resiliency



More important than the level of investment is the results our customers experience. Figure 9 compares PSEG Long Island's level of day-to-day system reliability to other utilities in New York and across the country. In 2017, on average, each Long Island customer experienced less than a single electric outage (0.95 outages per year) and was without power for 65.8 minutes⁴. **These results are among the best for large utilities in the Northeast and across the country -- equivalent to a car traveling 24-hours a day, 365 days a year, for 350,000 miles on one hour of service.**

FIGURE 9

Average Number of Minutes a Customer is Without Service is Among the Top 25 Percent of Utilities

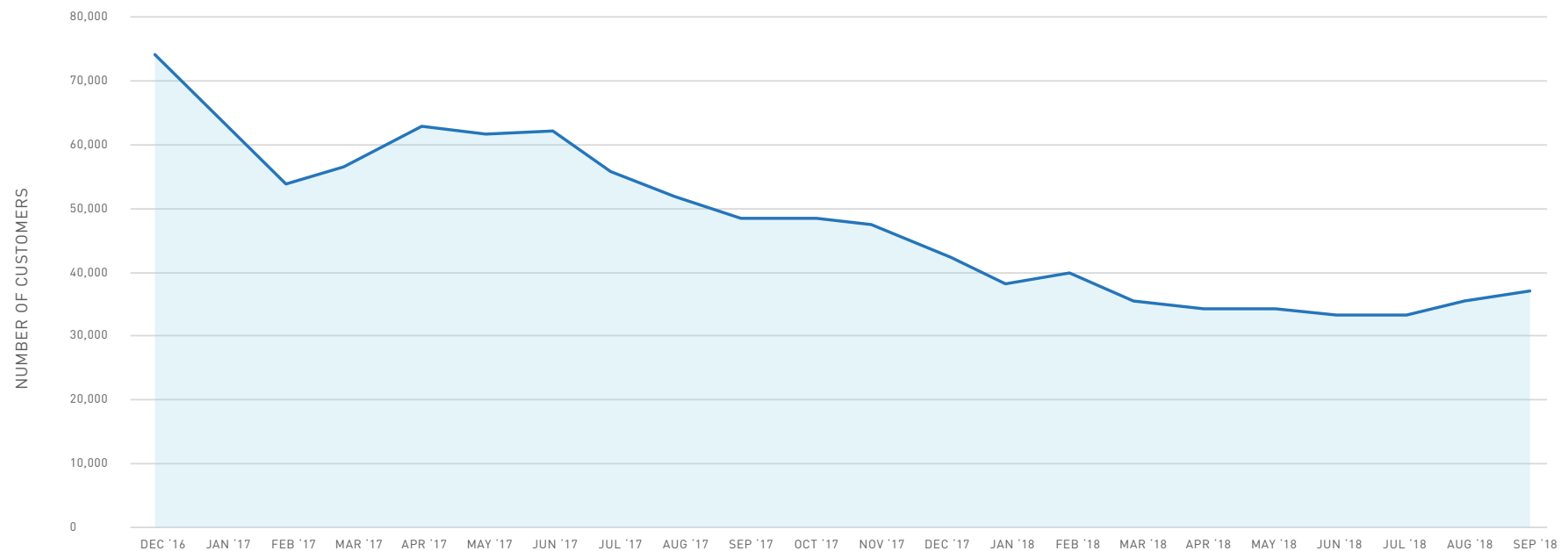


⁴ System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"), respectively.

While the average customer has favorable reliability, PSEG Long Island has also enhanced reliability for our customers with worse than average electric service. **The number of customers experiencing four or more outages in a year⁵ has declined from 70,248 in 2016, to 39,018 today, a decline of 45 percent**, as shown in Figure 10. We aim to further reduce this number over the next several years.

FIGURE 10

45 Percent Fewer Customers Experience Multiple Outages in a Year



⁵ CEMI-4, which stands for Customers Experiencing More Than Four Outages of five minutes or more in the past year

Reliability



Areas of focus for 2019 and beyond to enhance reliable service for customers include:

- > Powering up new projects to serve famed Long Island locations such as the Nassau Hub, Sloan Kettering, Nassau County Police Academy, and Belmont Racetrack;
- > Deploying Smart Wires to cost-effectively defer transmission investment by shifting power from overloaded to underutilized circuits;
- > Building the Western Nassau Transmission Project to make the electric grid more resilient and reliable; and
- > Upgrading the South Fork electric grid to meet growing energy demand.

Partnering with Long Island Rail Road to Enhance Service

PSEG Long Island is replacing 250 older transmission poles along the Long Island Rail Road over the next two years to improve electric grid reliability and minimize the risk of disruption to train service in bad weather.

- > Babylon Branch
- > Central Branch
- > Far Rockaway Branch
- > Mainline Branch
- > Montauk Branch
- > Oyster Bay Branch
- > Port Jefferson Branch



Syosset

Hewlett

AFFORDABLE ELECTRIC SERVICE FOR OUR CUSTOMERS

LIPA's mission is to provide "clean, reliable and affordable electric service for our customers." **As a publicly-owned electric utility, LIPA's electric rates reflect its costs to provide service with no profit margin.** Our business model – public ownership with a private operator – reduces the cost of electric service on Long Island by 20 percent or more⁶. The LIPA Board of Trustees has established goals to maintain electric rates that are:

- > At the lowest level consistent with sound fiscal and operating practices;
- > Comparable, and preferably at the lower end, of other regional utilities that surround LIPA's service territory; and
- > Affordable for households with low and moderate incomes.



⁶ Public ownership significantly reduces LIPA's cost of capital compared to privately-owned utilities by allowing the Authority to access the tax-exempt bond market, not pay dividends to shareholders, and eliminate corporate income tax payments embedded in private-utility electric rates. Additionally, LIPA is eligible for disaster recovery and storm hardening grants unavailable to private utilities, which reduces the cost to LIPA's customers of storm restoration in the event of severe weather events. LIPA has received more than \$1.5 billion of such federal and state grants.

EFFORTS TO MINIMIZE CUSTOMER BILLS ARE WORKING

LIPA and PSEG Long Island have taken many actions to achieve the Board's rate affordability policy. **Achieving a balance of service quality and cost requires reducing cost in areas that provide less value to customers while continuing to invest in customer service, clean energy, and reliability.**

Some of our cost saving initiatives since 2013 include:

- > Discontinuing investments in new combined cycle plants, as the declining cost of renewable energy will reduce the run-time and value of the plants;
- > Reducing taxes paid by LIPA on behalf of its customers by defending the LIPA Reform Act's two percent per year tax cap on transmission and distribution property in court and challenging unreasonably high tax assessments⁷;
- > Refinancing existing debt with higher-rated "triple-A" Utility Debt Securitization Authority bonds for savings;
- > Renegotiating expiring power purchase agreements for savings;
- > Investing in cost-effective energy efficiency to reduce Long Island's peak generation capacity needs;
- > Maintaining a flat PSEG Long Island operating budget for 2019, thereby offsetting inflation with productivity savings;
- > Reducing the long-term cost of pensions and retirement benefits imbedded in LIPA's Power Supply Agreement;
- > Re-negotiating gas transportation contracts;
- > Obtaining LIPA's share of corporate tax savings on power purchase agreements from the recently passed federal corporate tax bill;

- > Deploying distributed energy resources to defer transmission and distribution system investments in load pockets; and
- > Negotiating reductions to the New York Independent System Operator's state-wide transmission costs, when such costs disproportionately benefit other regions of the state.

Figure 11 shows the impact on 2019 electric rates from each of these initiatives. **The \$598 million in savings equals 17 percent of customer electric bills.** Without these initiatives, LIPA and PSEG Long Island would have been unable to fund the investments that have improved satisfaction for our customers over the last five years.

FIGURE 11

Savings in 2019 from Efforts to Manage Customer Bills :

Discontinuing investments in combined cycle plants	\$342M
LIPA Reform Act's 2% Tax Cap	\$100M
Refinancing existing debt	\$88M
Renegotiating expiring power purchase agreements	\$18.5M
Investing in cost-effective energy efficiency	\$15.6M
PSEG Long Island productivity savings	\$9.6M
PSA pension and retirement savings	\$8M
Corporate tax savings on power purchase agreements	\$6M
Reductions to gas transportation costs	\$6M
Transmission and distribution investment deferrals from distributed energy resources	\$3M
Reductions to New York Independent System Operator state-wide transmission costs	\$1.7M

TOTAL : **\$598.4M**
in savings to customers in 2019

⁷ See LIPA's Annual Report on Property Tax Reduction Efforts for more information.

Many of these cost saving initiatives have not realized their full potential. Additionally, LIPA and PSEG Long Island have several new initiatives that will add value for our customers, including:

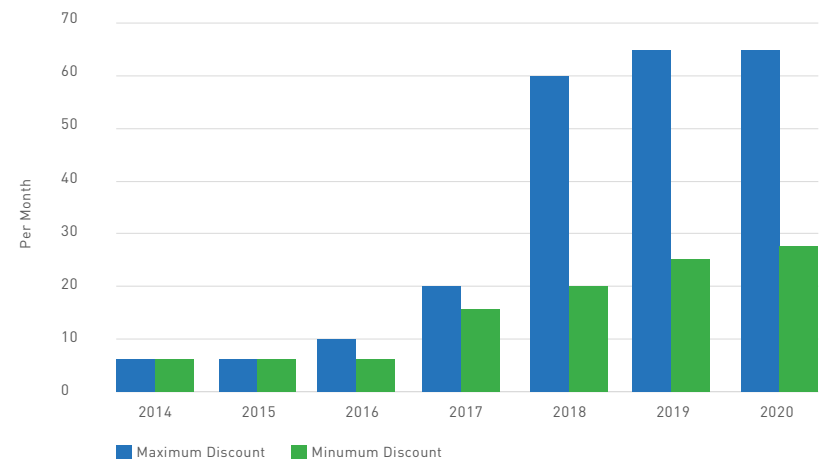
- > **Using technology to reduce cost and improve service**, such as the deployment of Smart Meters, which will reduce future electric rates while providing better service to customers;
- > **Encouraging cost-effective electrification of vehicles and heating**, thereby reducing Long Island's carbon footprint and spreading the fixed costs of maintaining the local electric grid over more kilowatt-hour sales; and
- > **Pursuing opportunities to “pre-pay” for electric and natural gas costs**, thereby securing a discount for our fuel and purchased power costs.

PROVIDING ASSISTANCE TO LOW AND MODERATE INCOME CUSTOMERS

In addition to maintaining overall rate affordability, LIPA's Board policy on Regionally Comparable Electric Rates ensures that electric rates are affordable for our customers with low and moderate incomes. LIPA and PSEG Long Island have taken actions, consistent with New York State policy, to provide an increased level of assistance to eligible customers. **Over the past five years, discounts available to eligible customers have increased from \$5 to anywhere between \$25 and \$65 per month**, depending on customer needs, as shown in Figure 12. When our discounts are fully phased-in for 2020, energy costs will be limited to, on average, no more than six percent of household income for low-income customers.

FIGURE 12

Increasing Low and Moderate Income Customer Discounts



2019 BUDGET by the NUMBERS

The 2019 Budget consists of an Operating Budget of \$3.599 billion and a Capital Budget of \$868.8 million. The Operating Budget, shown in Figure 13, funds delivery and power supply costs, energy efficiency and distributed energy programs, taxes, and debt service. The Capital Budget, summarized in Figure 14, funds long-life infrastructure investments such as transmission, substations, poles and wires, as well as information technology, bucket trucks, and other assets.

Figure 13

2019 Operating Budget (\$ thousands)

Operating Revenues	3,525,754
Grant & Other Income	73,092
Total Revenues and Income	3,598,846
Power Supply Costs	1,584,086
Delivery Costs	715,836
PILOTs, Taxes & Fees	536,675
Interest Payments	372,666
Debt Reduction & OPEB	389,583
Operating Budget	3,598,846
Fixed Obligation Coverage	
LIPA Debt Plus Leases	1.45x
LIPA & UDSA Debt Plus Leases	1.27x

Note: Operating Budget shown based on revenue requirements. Taxes on power supply have been reclassified to PILOTs, Taxes and Fees

Figure 14

2019 Capital Budget (\$ thousands)

Capital Projects	715,220
Storm Hardening	153,609
Capital Budget	868,829
Funding Sources	
Funding from Operating Budget	190,797
FEMA Grant	138,248
Debt Issued to Fund Projects	539,784
Funding Sources	868,829
Percent of Capital Projects Funded from Debt	
Including FEMA Projects	62%
Excluding FEMA Projects	73%

MEETING THE BOARD'S FINANCIAL POLICY FOR 2019

LIPA's Board of Trustees established goals to measure the prudence and sustainability of our financial performance. These include:

- > Achieving “mid-A” credit ratings by the end of 2020;
- > Long-term borrowing of no more than 64 percent of capital spending; and
- > Achieving fixed-obligation coverage of 1.45x on LIPA debt and capitalized leases⁸.

As a publicly-owned utility, there are only two sources of funds for the substantial capital investments required to maintain the physical electric grid on Long Island – electric rates and debt.⁹

The aim of the Board's financial policy is to reduce the cost of providing electric service to our customer-owners over the long-term.

Overborrowing and unsustainable financial policies can reduce electric rates today, at the expense of driving up future electric rates. Prudent fiscal and debt management reduces the cost our customers' pay to borrow funds and allows LIPA to appropriately spread the cost of long-life infrastructure investments over the useful life of the assets, ensuring that today's customers pay for a portion of the investment and that future customers, who will also benefit, pay an appropriate share of the cost too.

The Board's financial policy measures our fiscal prudence the way rating agencies and investors do. The importance of using the right measures as our guide is evident from the increase in our credit ratings over the last five years, as illustrated in Figure 15. This improved outlook has correspondingly reduced LIPA's borrowing cost.

FIGURE 15

LIPA Receives Credit Upgrades

These upgrades reflect rating agencies' expectations of continued improvement in our operational and financial performance.

	2013 RATING (Outlook)	2018 RATING (Outlook)
MOODY'S INVESTORS SERVICE	Baa1 (Negative)	A3 (Positive)
STANDARD AND POOR'S	A- (Negative)	A- (Positive)
FITCH RATINGS	A- (Negative)	A- (Stable)

As shown in Figures 13 and 14, the proposed 2019 Budget meets the Board's financial policy requirements. The Operating Budget achieves 1.45x fixed obligation coverage. The Capital Budget meets the Board's financial policy for borrowing, with new debt funding 62 percent of capital spending.

⁸ LIPA's financial policy targets fixed obligation coverage of 1.20x, 1.30x, 1.40x, and 1.45x for 2016, 2017, 2018, and 2019, respectively. The Board also targets a minimum of 1.25x fixed obligation coverage on the combination of LIPA debt, Utility Debt Securitization Authority debt, and capitalized leases.

⁹ As a public power utility, LIPA is also sometimes eligible for federal grants like those described above to fund 90 percent of our \$730 million storm hardening program; however, these are limited to specific purposes and for exceptional circumstances.

CHANGES IN THE 2019 OPERATING BUDGET

Figure 16 compares the \$3.53 billion 2019 Operating Budget to the \$3.52 billion 2018 budget. **The Operating Budget is increasing by \$4.1 million or 0.1 percent from the prior year.**

- > The budget includes annual updates to actual cost -- no more and no less -- for certain costs largely outside of LIPA and PSEG Long Island's control, as in prior years. **The net effect of these adjustments is to reduce electric rates by \$70.7 million.** These adjustments include:

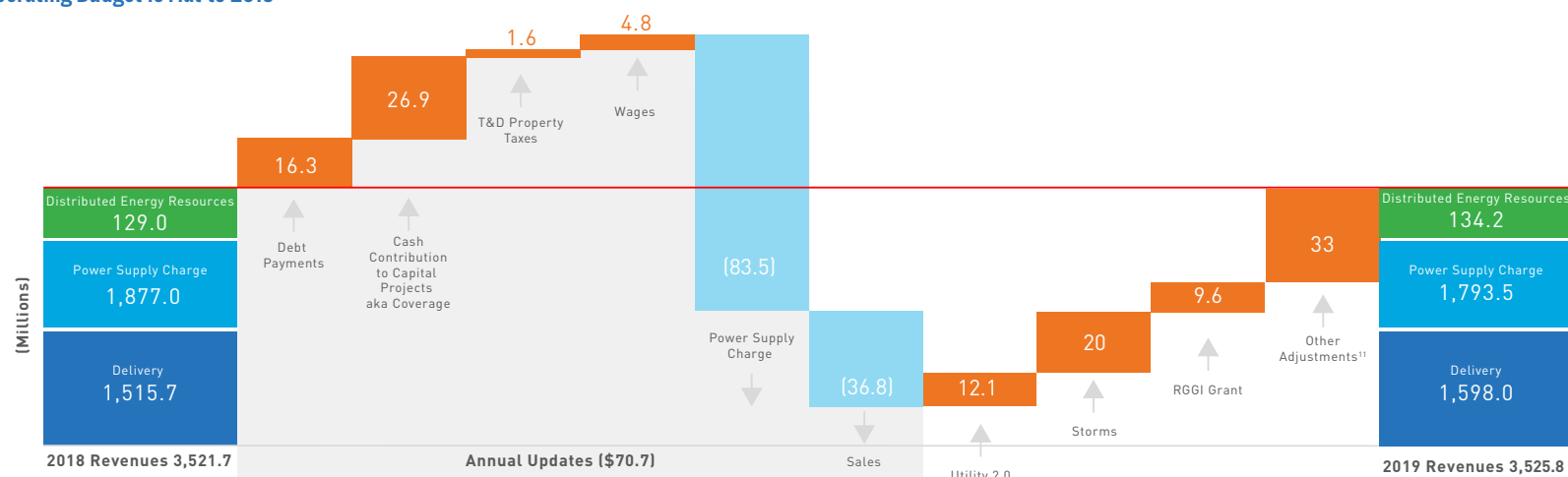
- Debt payments, multiplied by the related debt service coverage factor, net of interest earnings on investments;
- Taxes and fees paid by LIPA;
- Realized storm costs as compared to budget, net of insurance and federal disaster grants;

- Union wages;
- Power supply and fuel costs; and
- Sales.

- > The budget includes **\$12.1 million of incremental funding for PSEG Long Island's Utility 2.0 plan**, primarily for Smart Meters. This investment will provide customer benefits starting in 2019 and will provide customer savings by reducing operating costs, thereby having a favorable impact on electric rates, starting in 2022¹⁰;
- > Two additional changes in the 2019 budget, which are described below, are:
 - **A \$20 million increase in the budget for storm response**, consistent with the higher level of spending LIPA has experienced over the last five years; and
 - **A \$9.6 million decline in grant revenue for energy efficiency and renewable energy programs**, which will be made up for by an increase in the Distributed Energy Resources Charge on customer bills.

FIGURE 16

2019 Operating Budget is Flat to 2018



¹⁰ See PSEG Long Island's 2018 Utility 2.0 filing for more detail.

¹¹ Represents the difference in timing between the recognition of payments from customers and actual receipt of revenue.

STORM RESTORATION COSTS ARE RUNNING ABOVE BUDGET

Our customers expect timely storm and emergency response; however, the cost to restore the electric grid after a storm is volatile and largely unpredictable from year to year. Over the past five years, LIPA's annual cost for storm recovery has ranged from \$30.5 million in 2014 to \$112.3 million in 2016, net of insurance and federal grants for disaster recovery, as illustrated in Figure 17.

FIGURE 17

Long Island Experiencing More Severe Storms Requiring Mutual Aid

	2014	2015	2016	2017	2018
STORM SPENDING (\$'000)	30,462	63,210	112,337	66,574	108,111
NUMBER OF STORMS	16	19	20	13	14
STORMS REQUIRING MUTUAL AID	-	1	5	4	6
AVERAGE COST PER STORM (\$'000)	1,904	3,327	5,617	5,121	7,722

In a typical year, PSEG Long Island responds to between 13 and 20 storms. As Figure 17 shows, small differences in the severity of storms¹² from year to year can result in large differences in annual spending on storm response. LIPA attempts to minimize storm recovery costs for our customers in three ways:

- > First, **we maintain prudent levels of insurance, where such coverage is available and cost-effective.** Unfortunately, insurance is either unavailable for certain portions of the electric grid or the cost is too high to be economic for our customers.

- > Second, as a publicly-owned utility, **LIPA is eligible for federal disaster recovery grants that are unavailable to investor-owned utilities.** These grants are only available for the most severe of storms, such as Hurricane Irene or Superstorm Sandy, but as these storms are also the costliest to restore, this is an important protection for our customers.
- > Finally, as discussed in last year's budget message, **LIPA and PSEG Long Island have undertaken several initiatives aimed at hardening the electric grid**, including a \$730 million storm hardening program, 90 percent of which is funded via an agreement between Governor Cuomo and the Federal Emergency Management Agency. **Major storms will continue to cause damage to the electric grid, but a robust resiliency program reduces the damage caused by storms and speeds restoration times.**

As a customer-owned utility, the residual cost to restore the electric grid from storms is recovered from our customer-owners. There is no other source. While storm recovery spending is volatile from year to year, LIPA attempts to minimize this impact on customers by budgeting for a prudent level of storm spending each year and recovering any differences over time.

In 2015, LIPA established a "Delivery Service Adjustment" for electric rates to ensure customers pay only actual storm costs each year. Differences between budgeted and actual costs are reflected in charges or credits to customer bills in following years. This follows the practice the state's investor-owned utilities use to track and recover prudently incurred storm costs.

The 2019 budget increases the storm budget from \$34.9 million to \$54.9 million, based on recent levels of spending. **If the levels of the last five years represent what we should expect for the future, we believe it is prudent to budget more for storms.**

¹² The severity of storms is illustrated in Figure 17 by the number storms that require mutual aid from other utilities.

RECORD FUNDING FOR DISTRIBUTED ENERGY RESOURCES AND CLEAN ENERGY PROGRAMS

LIPA and PSEG Long Island are leading the way on New York's aggressive climate goals and this year's budget includes a record level of funding. Our distributed and clean energy programs are funded from three sources:

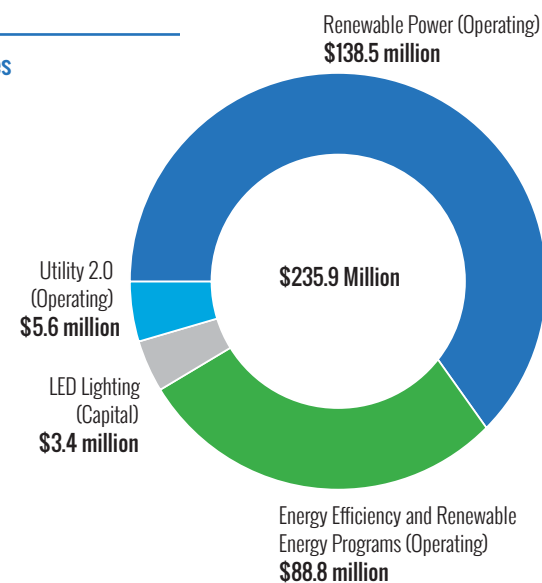
- > Purchases of renewable and zero carbon energy are funded by customers as part of the Power Supply Charge, which is set each month based on LIPA's actual cost, similar to other New York utilities;
- > Rebates and the costs to run energy efficiency and renewable energy programs, less any grants received for these programs, are funded from the Distributed Energy Resources ("DER") Charge on customer bills, which is similar to the System Benefits Charge on the bills of the state's investor-owned utilities; and
- > Capital investments in long-life infrastructure owned by LIPA that result in greater system efficiency are funded in the Capital Budget, resulting in debt repaid over the useful life of the investments, matching the benefits and the costs for our customers.

The 2019 budget continues our investments in distributed and clean energy programs with a record level of resources, as shown in Figure 18.

Funding for LIPA's distributed and clean energy programs is primarily from our customers; however, a portion is funded from grants received from the Regional Greenhouse Gas Initiative ("RGGI").

FIGURE 18

Distributed Energy Resources and Clean Energy Programs



RGGI is a cooperative effort among nine states – New York, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, Rhode Island, and Vermont – to reduce greenhouse gas emissions. LIPA buys CO2 allowances as part of its purchased power expense. A portion of these RGGI funds are returned to LIPA to fund energy efficiency and renewable energy programs on Long Island.

RGGI grant funding will decline by \$9.6 million from 2018 levels to \$25 million. This decline will increase the portion of such programs funded by customers through the DER Charge.

CHANGES IN THE 2019 CAPITAL BUDGET

Figure 19 shows the \$869 million 2019 Capital Budget as compared to the \$698 million 2018 budget. **The Capital Budget is increasing by \$171 million from the prior year.** Significant funding increases include:

- > **\$115 million for load growth**, with new projects such as the Nassau Hub and Belmont Racetrack, and upgrading the infrastructure on the South Fork;
- > **\$57 million for Utility 2.0 projects**, including replacing all conventional meters with smart meters over four years; and

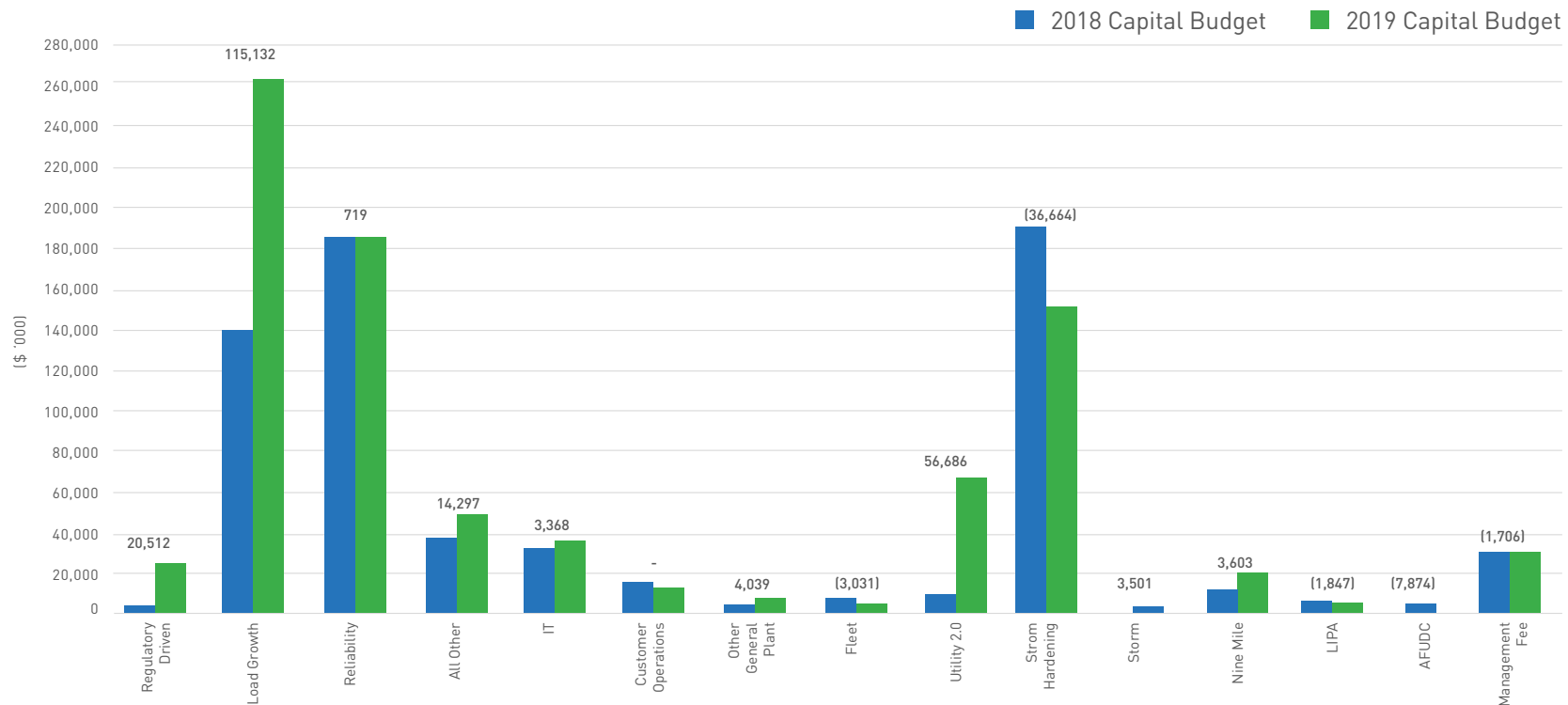
- > **\$21 million for regulatory driven projects**, such as the Western Nassau Transmission Project, which is required to meet new reliability standards.

The 2019 Capital Budget also includes \$154 million towards the \$730 million FEMA-funded storm hardening program.

The 2019 hardening program will rebuild 235 miles of distribution circuits with stronger wire and poles and install 75 smart switches to minimize outages on the electric grid.

FIGURE 19

\$869 Million 2019 Capital Budget Is Up \$171 Million Compared to 2018

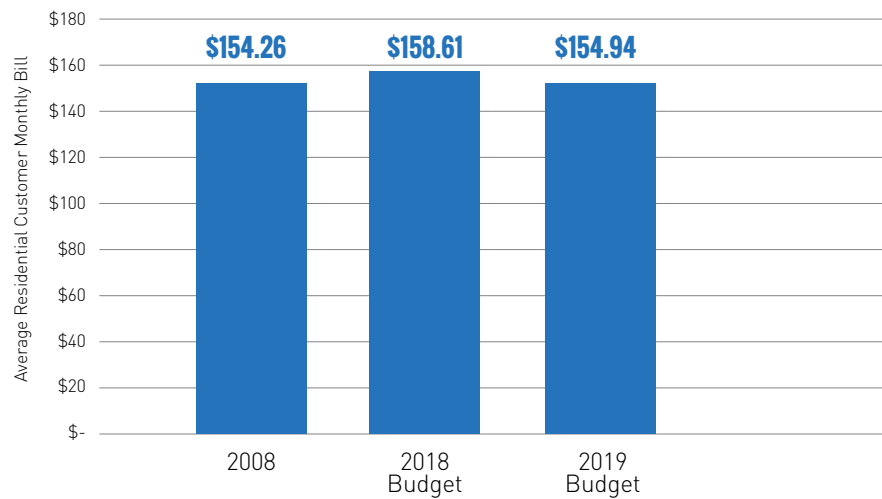


ELECTRIC BILLS FOR 2019

The impact of the 2019 Operating and Capital Budget can be shown in terms of residential customer bills. **Electric bills are forecast to decline by \$3.67 per month in 2019, or roughly two percent from their 2018 budgeted level.** Electric bills for an average residential customer have remained roughly flat for over a decade, increasing 0.4 percent since 2008, while inflation is up 21 percent over this period, as shown in Figure 20.

FIGURE 20

Customers' Electric Bills are Flat Over Last 10 Years



CONCLUSION

It is a privilege to work with the LIPA Board of Trustees and the employees of LIPA and PSEG Long Island to fulfill our mission of providing a clean, reliable and affordable utility for our customer-owners on Long Island and in the Rockaways.

The 2019 Budget funds our customers' priorities while holding the line on other spending and reducing electric bills for our customers. This favorable result reflects the cumulative effect of decisions made over the last several years. While we have more to do, our results since 2013 and our plans for the next several years show we are headed in the right direction.

Thomas Falcone
Chief Executive Officer
December 19, 2018



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A photograph of a white wind turbine against a clear blue sky, positioned on the left side of the page. The turbine's tower and nacelle are visible, with one blade extending upwards. The image is partially obscured by a diagonal blue and white graphic element.

LONG ISLAND POWER AUTHORITY 2019 BUDGET

SECTION II

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Revenue Requirements
(Thousands of Dollars)

Description	2018		2019		2020		Ref.
	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year	
PSEG Long Island Operating and Managed Expenses	\$ 607,590	\$ 668,076	\$ 637,650	\$ 30,060	\$ 649,882	\$ 12,232	10
PSEG Long Island OPEB Expense	40,669	49,284	43,955	3,286	44,934	979	31
PILOTS - Revenue-Based Taxes	33,127	34,157	34,321	1,194	36,028	1,707	6
PILOTS - Property-Based Taxes	289,280	287,481	292,861	3,581	298,718	5,857	14
LIPA Operating Expenses	77,012	78,080	83,619	6,607	85,290	1,671	33
Total Operating & Deferred Expenses	1,047,678	1,117,078	1,092,406	44,728	1,114,853	22,447	
PSEG Long Island OPEB Expense	(40,669)	(49,284)	(43,955)	(3,286)	(44,934)	(979)	31
Suffolk Property Tax Settlement	(21,714)	(23,148)	(24,041)	(2,327)	(26,630)	(2,589)	6 & 16
Visual Benefits Assessment	(428)	(499)	(414)	14	(436)	(22)	6 & 16
Less Non-Cash Items	(62,810)	(72,930)	(68,410)	(5,600)	(72,001)	(3,589)	
Other Interest Costs	26,487	24,790	19,022	(7,464)	19,043	21	20
Plus Cash Expenditures	26,487	24,790	19,022	(7,464)	19,043	21	
Less Other Income and Deductions	(40,258)	(47,765)	(44,242)	(3,983)	(43,334)	908	16
Less Grant Income	(38,429)	(38,450)	(28,850)	9,579	(28,688)	162	18
Total Cash Needed to Fund Operations	932,667	982,722	969,926	37,259	989,874	19,947	
LIPA Debt Service	192,978	198,570	216,803	23,824	270,486	53,683	22
UDSA Debt Service	324,728	324,728	327,140	2,412	319,030	(8,110)	22
Fixed Obligation Coverage	194,340	203,405	218,306	23,965	239,369	21,064	22
Debt Service	712,047	726,703	762,248	50,201	828,885	66,637	
Power Supply Charge	1,876,980	1,886,451	1,793,456	(83,524)	1,751,999	(41,457)	8
Total Revenue Requirements	\$ 3,521,694	\$ 3,595,876	\$ 3,525,630	\$ 3,936	\$ 3,570,758	\$ 45,127	6

Long Island Power Authority 2019 Proposed and 2020 Projected Operating and Capital Budgets

Revenue Requirements

The Authority's annual revenue requirements are budgeted to remain essentially flat from 2018 to 2019 at \$3.5 billion. Increases in property tax assessments, storm restoration costs, and debt service, including fixed obligation coverage are offset by decreases in the Power Supply Charge and other items. These costs are further detailed on the following pages herein.

Beginning in 2016, the Authority's revenue requirements have been calculated in accordance with the practices utilized by other large public power utilities in the United States (the Public Power Model) and reflect the recovery of operating expenses in the current year plus debt and other fixed payment obligations, including fiscally sound levels of fixed obligation coverage.

As set forth on page 2, the Authority's methodology for calculating revenue requirements and fixed obligation coverage excludes certain specified non-cash items. These exclusions reflect the non-cash portion of costs amortized to expense, such as depreciation and amortization (the costs of which are generally recovered in revenues through debt service payments) and the portion of expense associated with voluntary contributions to the Authority's OPEB Account, which are made after debt payments each year (and thus are first available to make debt payments and are thus part of fixed obligation coverage). The Authority's financial policies are further detailed herein in the description of debt service and fixed obligation coverage requirements.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Statements of Revenues and Expenses
(Thousands of Dollars)

Description	2017	2018		2019		2020		Ref.
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year	
Revenues	\$ 3,481,613	\$ 3,521,694	\$ 3,595,876	\$ 3,525,630	\$ 3,936	\$ 3,570,758	\$ 45,127	6
Power Supply Charge	1,842,587	1,876,980	1,886,451	1,793,456	(83,524)	1,751,999	(41,457)	8
Revenue Net of Power Supply Charge	1,639,026	1,644,714	1,709,425	1,732,174	87,460	1,818,759	86,585	
PSEG Long Island Operating and Managed Expenses								
PSEG Long Island Operating Expenses (a)	511,547	536,312	533,709	550,564	14,252	550,533	(31)	31
PSEG Long Island OPEB Expense	41,080	40,669	49,284	43,955	3,286	44,934	979	31
PSEG Long Island Managed Expenses	99,408	65,842	134,367	87,086	21,244	99,349	12,263	10
Utility Depreciation	165,884	189,410	179,024	201,340	11,930	232,682	31,343	12
Accelerated Depreciation of Conventional Meters	-	7,679	8,738	24,778	17,099	23,696	(1,082)	12
PILOTS - Revenue-Based Taxes	31,765	33,127	34,157	34,321	1,194	36,028	1,707	6
PILOTS - Property-Based Taxes	282,833	289,280	287,481	292,861	3,581	298,718	5,857	14
LIPA Operating Expenses	93,333	77,012	78,080	83,619	6,607	85,290	1,671	33
LIPA Deferred Amortized Expenses	31,015	31,015	31,015	25,015	(6,000)	25,015	-	12
LIPA Depreciation and Amortization	111,857	111,801	111,973	112,687	886	113,693	1,007	12
Interest Expense	336,071	343,505	348,559	358,693	15,189	357,147	(1,546)	20
Total Expenses	1,704,793	1,725,651	1,796,387	1,814,918	89,267	1,867,087	52,168	
Other Income and Deductions	43,638	40,258	47,765	44,242	3,983	43,334	(908)	16
Grant Income	39,251	41,778	41,318	34,078	(7,700)	39,191	5,113	18
Excess of Revenues Over Expenses (a)	\$ 17,122	\$ 1,100	\$ 2,122	\$ (4,424)	\$ (5,524)	\$ 34,197	\$ 38,622	

Note: (a) PSEG Long Island 2018 Approved Operating Expenses have been reduced by \$0.7 million due to carryover of O&M funding for the Utility 2.0 Super Saver program from 2018 to 2019. Thus, increasing the 2018 Approved Excess of Revenues Over Expenses from \$0.4 million to \$1.1 million.

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Statement of Revenues and Expenses

The Authority's projection of Revenues and Expenses uses the accrual basis of accounting, which results in a net loss of (\$4.4) million in 2019 and \$34.2 million of net income in 2020. Further information on the components of Revenues and Expenses are included on supplemental pages herein.

The factors contributing to the projection of net loss is the amortization of certain non-cash regulatory assets to expense, including non-cash employee benefits (OPEBs) for PSEG Long Island (page 31) and other deferred expenses (page 33). In addition, this includes an increase in depreciation associated with the early retirement of conventional meters as they are replaced by smart meters.

As shown on page 22, despite these "book" net losses, the Authority is forecasting to achieve higher levels of fixed obligation coverage and an increase in the amount of cash flow available to fund its capital program in lieu of debt financing. This is consistent with the Authority's financial goals to improve its credit ratings and reduce reliance on debt funding of its capital plan over five years.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Sales and Revenues

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
Sales of Electricity (MWh)							
Residential Sales	9,088,624	9,239,265	9,431,855	8,888,795	(350,470)	8,696,999	(191,796)
Commercial Sales	9,401,246	9,625,647	9,544,368	9,463,652	(161,996)	9,514,616	50,964
Other Sales to Public Authorities/Street Lighting	557,344	533,528	547,524	537,992	4,464	538,316	324
Total Sales of Electricity (MWh)	19,047,214	19,398,440	19,523,747	18,890,438	(508,002)	18,749,930	(140,508)

Revenues by Sector (Thousands of Dollars)														
Residential	\$	1,821,582	\$	1,893,044	\$	1,966,730	\$	1,863,586	\$	(29,458)	\$	1,888,485	\$	24,899
Commercial		1,471,332		1,500,458		1,480,635		1,517,399		16,941		1,566,141		48,742
Other Public Authorities/Street Lighting		68,404		73,723		68,907		65,881		(7,842)		65,788		(93)
ESCO Revenue		93,708		105,383		98,684		95,691		(9,692)		93,905		(1,785)
Power Supply Charge Deferral		(15,606)		-		18,894		-		-		-		-
Other Regulatory Amortizations and Deferrals		11,912		(80,100)		(64,515)		(45,650)		34,450		(72,285)		(26,635)
Miscellaneous Revenues		30,281		29,186		26,541		28,724		(462)		28,724		-
Total Revenues	\$	3,481,613	\$	3,521,694	\$	3,595,876	\$	3,525,630	\$	3,936	\$	3,570,758	\$	45,127

Revenues by Component (Thousands of Dollars)														
Delivery Charge (RDM Target)	\$	1,124,970	\$	1,226,328	\$	1,198,288	\$	1,305,096	\$	78,768	\$	1,378,921	\$	73,825
Power Supply Charge		1,858,193		1,876,980		1,867,557		1,793,456		(83,524)		1,751,999		(41,457)
T&D Property Tax	(a)	282,833		289,280		287,481		292,861		3,581		298,718		5,857
Energy Efficiency and Renewable Energy (DER)		52,244		56,178		57,525		63,617		7,439		66,726		3,109
New York State Assessment		10,859		10,510		9,858		9,453		(1,057)		9,642		189
Suffolk Property Tax Settlement		44,853		45,274		46,708		46,233		959		47,336		1,103
Visual Benefits Assessment (VBA)		961		948		1,019		909		(39)		901		(7)
Revenue Related PILOTS		31,765		33,127		34,157		34,321		1,194		36,028		1,707
RDM Collection/(Refund)	(b)	59,958		3,963		83,589		(32,873)		(36,836)		-		32,873
DSA Collection/(Refund)		(11,609)		29,915		28,773		31,380		1,465		24,048		(7,332)
T&D Property Tax Collection/(Refund)		-		106		-		(1,897)		(2,003)		-		1,897
Power Supply Charge Deferral		(15,606)		-		18,894		-		-		-		-
Other Regulatory Amortizations and Deferrals		11,912		(80,100)		(64,515)		(45,650)		34,450		(72,285)		(26,635)
Miscellaneous Revenues		30,281		29,186		26,541		28,724		(462)		28,724		-
Total Revenues	\$	3,481,613	\$	3,521,694	\$	3,595,876	\$	3,525,630	\$	3,936	\$	3,570,758	\$	45,127

Note: (a) T&D Property Tax is a component of Delivery Charge.

(b) The projected 2018 RDM collection totaling \$83.6 million reflects (i) the 2017 uncollected delivery revenue totaling \$14.8 million plus (ii) the projected 2018 delivery revenue shortfall. The 2019 RDM refund totaling \$32.9 million reflects the 2018 estimated overcollection of delivery revenue to be refunded to customers in 2019.

Long Island Power Authority 2019 Proposed and 2020 Projected Operating and Capital Budgets

Sales and Revenues

Revenues are derived primarily from retail sales of electricity to residential and commercial customers. Also included are revenues from electric sales to public authorities and street lighting. In accordance with the Authority's Tariff for Electric Service (the Tariff), the Authority's Delivery Charge recovers the costs associated with maintaining and improving its transmission and distribution system and serving its customers. Additionally, the Authority recovers costs associated with purchasing and producing electric energy (fuel and purchased power) through the Power Supply Charge. The Authority also has various surcharges and non-electric service charges, such as those to recover costs associated with its distributed energy programs, assessments, revenue-related PILOTs, fees for pole attachments, late payment charges to customers whose bills are in arrears, and other miscellaneous service fees.

PSEG Long Island's sales forecast projects an average annual 1.7% decline in sales through 2020, reflecting the impact of PSEG Long Island's energy efficiency programs combined with voluntary measures taken by customers, PV rooftop solar, and improvements to standards and codes. Any surplus/shortfall in delivery revenue due to sales being higher/lower than budgeted will be returned/recovered through the Revenue Decoupling Mechanism (RDM). The sales forecast assumes historically average weather conditions over the period.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Power Supply Charge (Thousands of Dollars)								
Description	2017 Actual	2018		2019		2020		
		Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year	
Capacity								
Capacity Charges	\$ 376,354	\$ 401,805	\$ 408,175	\$ 395,312	\$ (6,494)	\$ 377,544	\$ (17,767)	
National Grid (PSA)	266,657	263,864	240,630	253,561	(10,303)	260,652	7,090	
Total Capacity	643,012	665,669	648,805	648,873	(16,796)	638,196	(10,677)	
Purchased Power								
Purchased Power	391,241	367,021	364,559	361,293	(5,728)	344,242	(17,051)	
Total Purchased Power	391,241	367,021	364,559	361,293	(5,728)	344,242	(17,051)	
Commodity								
Natural Gas	275,041	262,475	293,929	211,166	(51,310)	204,725	(6,441)	
Fuel Oil	29,320	49,614	71,155	39,572	(10,042)	33,823	(5,749)	
Total Commodity	304,362	312,089	365,084	250,738	(61,352)	238,548	(12,190)	
Renewables								
Renewable Power	136,205	135,007	122,484	138,453	3,446	137,247	(1,207)	
Total Renewables	136,205	135,007	122,484	138,453	3,446	137,247	(1,207)	
Other								
Transmission	38,980	42,902	38,473	37,245	(5,658)	37,301	56	
Nine Mile Nuclear Fuel	41,085	43,346	44,028	45,006	1,660	44,472	(534)	
Regional Greenhouse Gas Initiative (RGGI)	12,342	20,698	15,810	18,348	(2,350)	19,419	1,072	
Zero Emissions Credits	32,921	45,862	45,329	50,014	4,152	51,398	1,384	
Fuel and Power Supply Management Services	19,301	19,924	19,605	19,724	(200)	20,085	361	
Other	12,027	12,711	14,772	14,393	1,682	7,920	(6,472)	
Total Other	156,656	185,443	178,017	184,729	(713)	180,596	(4,134)	
Pass Through Property Taxes								
National Grid (PSA)	195,633	196,016	193,990	198,653	2,637	202,302	3,649	
Fast Track Units	11,435	11,725	9,156	6,725	(5,000)	6,837	112	
Nine Mile	4,044	4,010	4,355	3,992	(18)	4,032	40	
Total Pass Through Property Taxes	211,112	211,751	207,501	209,370	(2,381)	213,171	3,801	
Total Power Supply Charge	\$ 1,842,587	\$ 1,876,980	\$ 1,886,451	\$ 1,793,456	\$ (83,524)	\$ 1,751,999	\$ (41,457)	

Long Island Power Authority 2019 Proposed and 2020 Projected Operating and Capital Budgets

Power Supply Charge

Power Supply Charges are budgeted at \$1.8 billion for 2019, a decrease of \$83.5 million compared to 2018. An additional \$41.5 million decrease is projected for 2020. The largest driver of the decrease is lower projected energy sales and commodity prices, including the impact of the Authority's hedge positions, which reduces the cost of Long Island generated energy and the cost of purchased power. See Table 1 below for a summary of the primary drivers of the decline.

Power supply costs projections are prepared utilizing a generation economic dispatch model that considers, among other variables, the availability and thermal efficiency of generating resources, delivered fuel prices, and environmental regulatory requirements.

In addition to the commodity costs consumed in generation and purchased power, power supply costs include the cost of emission allowances, generation and transmission cable capacity, the Authority's share of costs charged by the New York, New England and PJM independent system operators (ISO), electric power wheeling, payments made to Energy Service Companies (ESCOs) in accordance with the Long Island Choice program, Zero Emission Credits associated with the adoption by the New York State Public Service Commission of the Clean Energy Standard, services received under energy, power and fuel management agreements, fuel hedging program costs, energy from renewable resources as well as the Authority's 18% share of the operation and maintenance expenses related to the Nine Mile Point 2 nuclear generating station, the National Grid Power Supply Agreement, and certain PILOTs.

Table 1: 2019 vs. 2018 Change in Costs

Description	Net Change	Cause
Capacity	(\$16.8M)	Lower contract pricing and a decrease in PSA OPEB & Pension expense; partially offset by expiration of the Empire Zone tax refund for Caithness I.
Purchased Power	(\$5.7M)	Lower projected natural gas prices.
Commodity (gas & oil)	(\$61.4M)	Lower projected energy sales and gas prices and a projected gain in financial settlements from hedging. Reduction in residual oil use based upon updated historical data. Reduction in gas transportation costs.
Renewables	\$3.4M	Expected installation of additional solar projects.
Other	(\$0.7M)	Reduction in emissions costs and updated charges for the Y49 cable and ZEC payments.
Pass Through Property Taxes	(\$2.4M)	Taxes associated with the Brentwood and Shoreham PPAs are now borne by the facilities' owners.
Total	(\$83.5M)	

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Operating Expenses
(Thousands of Dollars)

Description	2017 Actual	2018		2019		2020	
		Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
PSEG Long Island Operating Expenses	(a) \$ 552,627	\$ 576,981	\$ 582,993	\$ 594,519	\$ 17,538	\$ 595,468	\$ 949
Capital Lease Offsets	(b) -	(5,436)	-	-	5,436	-	-
PSEG Long Island Managed Expenses							
Uncollectible Accounts	18,960	22,923	15,971	19,867	(3,056)	20,104	237
Storm Restoration	66,574	34,854	108,111	54,854	20,000	66,472	11,618
NYS Assessment	10,859	10,510	9,858	9,453	(1,057)	9,642	189
Accretion of Asset Retirement Obligation	2,638	2,831	134	2,750	(81)	2,969	219
Miscellaneous	376	160	293	162	2	162	-
Total PSEG Long Island Managed Expenses	99,408	65,842	134,367	87,086	21,244	99,349	12,263
Total PSEG Long Island Operating and Managed Expenses	652,035	642,823	717,359	681,605	38,782	694,817	13,212
LIPA Operating Expenses							
Management Fee (including incentive)	72,565	74,604	74,102	75,584	980	77,095	1,511
Capitalized Management Fee	(c) (9,748)	(30,632)	(26,794)	(28,926)	1,706	(29,504)	(578)
LIPA Operating Costs	30,516	33,040	30,773	36,961	3,921	37,699	738
LIPA Operating Expenses	93,333	77,012	78,080	83,619	6,607	85,290	1,671
PSEG Long Island & LIPA Total Operating Expenses	\$ 745,368	\$ 719,835	\$ 795,439	\$ 765,224	\$ 45,389	\$ 780,107	\$ 14,883

Note: (a) PSEG Long Island 2018 Approved Operating Expenses have been reduced by \$0.7 million due to carryover of O&M funding for the Utility 2.0 Super Saver program from 2018 to 2019.

(b) Due to the immaterial nature of this item, reclassing vehicle lease expense from PSEG Long Island's operating expenses is no longer required.

(c) Effective in 2018, a new methodology based on the PSEG Long Island company labor allocation was adopted for determination of the Capitalized Management Fee. As a result the portion of the management fee allocated to capital increased from (\$9.7M) in 2017 to (\$30.6M) in 2018.

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Operating Expenses

Total Operating Expenses are budgeted at \$765.2 million in 2019 and projected at \$780.1 million in 2020.

Operating Expenses are comprised of costs associated with operating and maintaining the Authority's Transmission and Distribution system consisting of three major expense categories:

- (i) PSEG Long Island Operating Expenses (expenses which PSEG Long Island must remain within 102% of budget to earn incentive compensation);
- (ii) PSEG Long Island Managed Expenses (expenses which PSEG Long Island manages but are substantially outside of the control of PSEG Long Island); and
- (iii) LIPA's Operating Expenses

PSEG Long Island Operating Expenses include costs related to the following major areas: Transmission and Distribution, Customer Services, Business Services, Power Markets and Energy Efficiency and Renewable Energy Programs. The budget for the Energy Efficiency and Renewable Energy Programs provides for additional peak load and energy reductions as well as customer-based solar and wind distributed generation, among other things. PSEG Long Island Operating Expenses for 2019 and 2020 include additional costs related to the Utility 2.0 Plan. These costs are associated with projects aimed at integrating smart meters and Distributed Energy Resources (DER) in the Authority's electric grid.

PSEG Long Island Managed Expenses include costs related to New York State assessments, uncollectible accounts, and storm preparation and restoration. The budget for storm preparation and restoration costs is increasing to \$54.9 million for 2019 and \$66.5 million for 2020. The budget phases in a historical three-year average level of spending on storm restoration.

LIPA Operating Expenses includes the PSEG Long Island management fee and costs related to the Authority staff and outside professional services, as detailed on page 33.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Depreciation and Amortization Expenses
(Thousands of Dollars)

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
PSEG Long Island Managed Utility Depreciation	\$ 164,984	\$ 185,688	\$ 175,838	\$ 195,531	\$ 9,842	\$ 221,012	\$ 25,482
Accelerated Depreciation of Conventional Meters	-	7,679	8,738	24,778	17,099	23,696	(1,082)
Depreciation Expense Related to FEMA Capital Projects	900	3,722	3,186	5,809	2,087	11,670	5,861
Total PSEG Long Island Managed Utility Depreciation	165,884	197,089	187,762	226,118	29,029	256,378	30,261
LIPA Depreciation and Amortization							
Amortization of Acquisition Adjustment	111,375	111,375	111,375	111,375	-	111,375	-
Depreciation - LIPA	482	426	598	1,312	886	2,318	1,007
Total LIPA Depreciation and Amortization	111,857	111,801	111,973	112,687	886	113,693	1,007
Total Depreciation and Amortization	277,741	308,890	299,735	338,804	29,915	370,072	31,267
Amortization of OPEB & Pension Deferrals	(a) 31,014	31,015	31,015	25,015	(6,000)	25,015	-
Total Depreciation and Amortization Expenses	\$ 308,755	\$ 339,904	\$ 330,750	\$ 363,819	\$ 23,915	\$ 395,086	\$ 31,267

Note: (a) Amortization of OPEB and Pension Deferrals is reduced starting in 2019 to reflect impact of the favorable resolution of previously established reserves.

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Depreciation and Amortization Expenses

Depreciation and Amortization Expenses are budgeted at \$363.8 million in 2019 and projected at \$395.1 million in 2020.

PSEG Long Island Managed Utility Depreciation consists of depreciation of transmission and distribution, information technology, and FEMA storm hardening assets.

The budgeted Utility depreciation for 2019 and projected for 2020 reflects increases of approximately \$24.8 million and \$23.7 million, respectively, resulting from the early retirement of conventional meters replaced by smart meters. Depreciation expense will increase throughout the entire smart meter implementation program, which is expected to be completed in 2022, as conventional meters are taken out of service.

LIPA Depreciation and Amortization consists primarily of the amortization of the Acquisition Adjustment budgeted at \$111.4 million annually. The Acquisition Adjustment is an intangible asset resulting from the merger with the Long Island Lighting Company in 1998.

Also included is the amortization of certain regulatory assets related to pension and OPEB expenses for the former National Grid and current PSEG Long Island employees that directly serve the Authority's customers. These retirement benefit expenses are a contractual obligation of the Authority and are being amortized to align the expenses to coincide with the term of employment of the workforce contracted by the Authority under the Amended and Restated Operations Services Agreement. See the Authority's audited financial statements for more information.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Taxes, Payments-in-Lieu of Taxes and Assessments (Thousands of Dollars)								
Description	2017	2018		2019		2020		
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year	
PILOTS - Revenue-Based Taxes	\$ 31,765	\$ 33,127	\$ 34,157	\$ 34,321	\$ 1,194	\$ 36,028	\$ 1,707	
PILOTS - Property-Based Taxes	(a) 282,833	289,280	287,481	292,861	3,581	298,718	5,857	
Property Taxes in Power Supply Charge								
National Grid (PSA) Property Taxes	195,633	196,016	193,990	198,653	2,637	202,302	3,649	
Fast Track Units	11,435	11,725	9,156	6,725	(5,000)	6,837	112	
Nine Mile PILOTS	4,044	4,010	4,355	3,992	(18)	4,032	40	
Total Property Taxes in Power Supply Charge	211,112	211,751	207,501	209,370	(2,381)	213,171	3,801	
Other Taxes and Assessments								
NYS Conservation Assessment	1,795	-	-	-	-	-	-	
NYS Department of Public Service	9,065	10,510	9,858	9,453	(1,057)	9,642	189	
NYS Office of Real Property Services	152	160	167	162	2	162	-	
Total Other Taxes and Assessments	11,012	10,669	10,026	9,615	(1,055)	9,804	189	
Total PILOTS, State and Local Taxes and Assessments	\$ 536,721	\$ 544,828	\$ 539,165	\$ 546,167	\$ 1,340	\$ 557,721	\$ 11,554	

Note: (a) The 2019 PILOTS - Property Based Taxes increase of \$3.6 million from 2018 Approved excludes the change in the T&D Property Tax Refund, which stems from the prior year's overcollection, of \$2.0 million. The resulting net year-over-year increase is \$1.6 million.

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Taxes, Payments-in-Lieu of Taxes and Assessments

Payments-In-Lieu of Taxes (PILOTs) and Assessments are budgeted at \$546.2 million in 2019 and projected at \$557.7 million in 2020.

Revenue-based PILOTs are calculated using gross revenues received from the sale of electricity and other sources of revenue and are subject to true up to actual cost through a PILOT payments recovery rider.

Property-based PILOTs are for payments on LIPA owned properties. The LIPA Reform Act establishes a 2% cap in the increase in T&D property based PILOT payments allowable each year beginning in 2015.

Additionally, LIPA also incurs property-based taxes associated with the generating assets under contract through the National Grid Power Supply Agreement (PSA). These taxes are budgeted at \$209.4 million in 2019 and projected at \$213.2 million in 2020. The Authority continues to challenge the property tax assessments on the PSA generation assets, which are significantly over-assessed.

The property-based PILOTs related to the Fast Track Units are budgeted to decrease as a result of renewed power purchase agreements whereby the taxes for two property locations are now the responsibility of the owner of the generation units. These costs, as with all power supply costs, are reconciled to actual costs.

The New York State Department of Public Service (DPS) Administrative Assessment will be imposed to recover costs related to DPS' oversight of PSEG Long Island's operations. This cost is approximately \$9.5 million per year.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Other Income and Deductions
(Thousands of Dollars)

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
Short-Term Investment Income	\$ 3,110	\$ 3,597	\$ 7,038	\$ 5,970	\$ 2,374	\$ 5,942	\$ (28)
Interest from Shoreham Property Tax Settlement	24,822	23,560	23,560	22,192	(1,368)	20,706	(1,486)
Interest from Visual Benefits Assessment	543	520	520	495	(25)	465	(29)
Interest from Nuclear Decommissioning Trust Fund	5,250	3,394	4,271	5,000	1,606	5,000	-
Interest from OPEB Fund	4,724	2,889	4,521	4,182	1,293	4,913	731
Interest from PSEG Long Island Funding Accounts	734	692	1,468	1,461	769	1,476	15
Miscellaneous Income and Deductions - LIPA	2,770	3,994	3,728	2,843	(1,151)	2,843	-
Miscellaneous Income and Deductions - PSEG Long Island	1,685	1,612	2,659	2,099	487	1,989	(110)
Total Other Income and Deductions	\$ 43,638	\$ 40,258	\$ 47,765	\$ 44,242	\$ 3,983	\$ 43,334	\$ (908)

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Other Income and Deductions

Other Income and Deductions are budgeted at \$44.2 million for 2019 and projected at \$43.3 million for 2020. The budget and projections are based on forecasted account balances and interest rates.

Other Income and Deductions consists of income and interest generated from the Authority's short-term investments, earnings on the Nine Mile Point 2 nuclear decommissioning trust fund, earnings on the unrestricted OPEB Account, carrying charges accrued on deferred balances related to the Shoreham property tax settlement, and miscellaneous sources of revenues and expenses, such as income from certain customer-requested work not included in electric rates.

Projected interest rates on short-term investments are updated to prevailing interest rates annually as part of the budget process and differences between projected and actual interest rates are reconciled annually through the Delivery Service Adjustment.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Grant Income
(Thousands of Dollars)

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
Build America Bonds Subsidy - U.S. Treasury	\$ 3,841	\$ 3,829	\$ 3,850	\$ 3,850	\$ 21	\$ 3,688	\$ (162)
Efficiency & Renewables - RGGI Funding	34,600	34,600	34,600	25,000	(9,600)	25,000	-
Total Grant Income	38,441	38,429	38,450	28,850	(9,579)	28,688	(162)
Recognition of Deferred FEMA Grant / Sandy	810	3,350	2,868	5,228	1,879	10,503	5,275
Total Grant Income & Deferred Credit	\$ 39,251	\$ 41,778	\$ 41,318	\$ 34,078	\$ (7,700)	\$ 39,191	\$ 5,113

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Grant Income

In 2019, Grant Income consists primarily of a (i) grant of \$25.0 million from NYSERDA Regional Greenhouse Gas Initiative (RGGI) funds to support PSEG Long Island's energy efficiency programs and (ii) subsidy payments totaling \$3.9 million from the United States Treasury equal to approximately 33% of the interest on the Authority's debt issued as Build America Bonds.

The current agreement with NYSERDA for the RGGI grant expired at the end of 2018. This grant has been extended to provide \$25.0 million annually in 2019 and 2020. The Authority pays for RGGI allowances as part of its Power Supply Charge. This grant represents the return of a portion of those funds to run environmental programs.

In February 2014, the Authority signed a Letter of Undertaking with FEMA that provides for \$730.0 million of grant funding for storm hardening measures. To better reflect the nature of this grant it will be amortized to Grant Income in an amount equal to the incremental depreciation expense incurred as a result of the storm hardening program. This amortization is estimated at \$5.2 million in 2019 and \$10.5 million in 2020.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Interest Expense
(Thousands of Dollars)

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
Accrued Interest Expense on Debt Securities	\$ 342,552	\$ 347,542	\$ 357,352	\$ 372,666	\$ 25,124	\$ 378,775	\$ 6,109
Amortization of Premium	(53,836)	(55,305)	(58,400)	(60,857)	(5,551)	(64,677)	(3,821)
Net Interest Expense on Debt Securities	288,716	292,236	298,952	311,809	19,573	314,097	2,288
Other Interest Expense							
Amortization of Deferred Debt Issue Costs	3,327	3,210	3,326	5,291	2,081	5,737	446
Amortization of Deferred Defeasance Costs	30,513	32,128	32,285	29,304	(2,824)	25,129	(4,175)
Other Interest Amortizations	(6,392)	(3,363)	(6,612)	(6,733)	(3,370)	(6,859)	(126)
Capital Lease Interest (a)	-	680	-	-	(680)	-	-
Other Interest Amortizations	27,447	32,655	28,999	27,862	(4,793)	24,007	(3,855)
Interest Rate Swap Payments	16,899	16,234	15,819	10,388	(5,846)	10,394	6
Letter of Credit and Remarketing Fees	7,094	8,825	7,146	6,827	(1,998)	6,842	15
Interest on Customer Security Deposits	197	19	394	392	373	392	0
Bond Administration Costs and Bank Fees	1,624	1,409	1,431	1,415	6	1,415	-
Other Interest Costs	25,813	26,487	24,790	19,022	(7,464)	19,043	21
Subtotal - Interest Expense	341,976	351,378	352,741	358,693	7,315	357,147	(1,546)
Less: Capitalized Interest (b)	5,904	7,874	4,182	-	(7,874)	-	-
Total Interest Expense	\$ 336,071	\$ 343,505	\$ 348,559	\$ 358,693	\$ 15,189	\$ 357,147	\$ (1,546)

Note: (a) Due to the immaterial nature of this item, reclassing vehicle lease expense from PSEG Long Island's operating expenses is no longer required.

(b) Due to a change in a new accounting treatment Capitalized Interest is eliminated effective in 2019.

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Interest Expense

Interest expense is budgeted at \$358.7 million in 2019 and projected at \$357.1 million in 2020. The budget is based on forecasted levels of outstanding debt, associated fees, and the amortization of previously deferred debt-related charges and credits. Actual interest rates are updated to prevailing interest rates each year as part of the annual budget process and differences between projected and actual interest rates are reconciled annually through the Delivery Service Adjustment ensuring customers pay actual costs.

Interest expense reflects the accrual of interest on outstanding debt in the calendar year. It can differ from interest payments made to bond holders with respect to timing, but the actual amounts will be the same over the life of the bonds.

Amortization of premiums remains at a consistent level in 2019 compared to 2018. A significant portion of the amortization of premiums is a result of the issuance of securitization bonds by the Utility Debt Securitization Authority (UDSA) on behalf of the Authority. The UDSA bonds were sold at a premium to their par value, and the premium is being amortized over the life of each series of bond issued. The UDSA refinancing generated approximately \$492.0 million in net present value debt service savings for LIPA customers.

The Authority will no longer capitalize interest expense beginning in 2019 due to a change in accounting requirements related to GASB Statement No. 89.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Debt Service Requirements (Thousands of Dollars)								
Description	2017	2018		2019		2020		
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year	
UDSA Debt Service	\$ 264,811	\$ 324,728	\$ 324,728	\$ 327,140	\$ 2,412	\$ 319,030	\$ (8,110)	A
LIPA Debt Service on Fixed Rate Debt	225,591	156,543	156,543	164,947	8,404	222,999	58,052	B
LIPA Debt Service on Variable Rate Debt	23,279	23,602	29,194	34,010	10,408	34,001	(9)	C
LIPA Debt Service due to Capital Borrowings	-	12,833	12,833	17,845	5,012	13,485	(4,361)	D
Subtotal UDSA Debt Service	264,811	324,728	324,728	327,140	2,412	319,030	(8,110)	A
Subtotal LIPA Debt Service	248,870	192,978	198,570	216,803	23,824	270,486	53,683	E=B+C+D
Total Debt Service	513,681	517,707	523,299	543,943	26,236	589,516	45,573	F
Total Coverage Requirements	184,338	194,501	189,609	218,306	23,804	239,369	21,064	G
Total Debt Service plus Coverage	\$ 698,019	\$ 712,208	\$ 712,908	\$ 762,248	\$ 50,040	\$ 828,885	\$ 66,637	H
LIPA Long Term Obligations	(a) 308,276	293,274	275,453	267,076	(26,199)	261,446	(5,629)	I
Excess Revenue Net of Requirements	(b)	(161)	13,795	-	161	-	-	J
Total Coverage	184,338	194,340	203,405	218,306	23,965	239,369	21,064	K=G+J
Projected Coverage Ratio on LIPA Obligations	1.33 x	1.40 x	1.43 x	1.45 x		1.45 x		L=1+K/(E+I)
Board Policy Target Coverage Ratio on LIPA Obligations		1.40 x	1.40 x	1.45 x		1.45 x		
Projected Coverage on LIPA & UDSA Obligations	1.22 x	1.24 x	1.25 x	1.27 x		1.28 x		M=1+K/(F+I)
Board Policy Target Coverage on LIPA & UDSA Obligations		1.25 x	1.25 x	1.25 x		1.25 x		

Note: (a) The 2020 Capital Lease and Long-term Obligation amounts and the associated Coverage calculation do not reflect GASB No. 87 implementation.

(b) The 2018 Approved Excess Revenue Net of Requirements changed from (\$3.8) million to (\$0.2) million due to (i) PSEG Long Island 2018 Approved Operating Expenses decrease of \$0.7 million plus (ii) a change in the methodology in calculating LIPA's coverage from utilizing the Cash Contribution to the Pension Trust to the Non Cash Pension Accrual Expense.

Long Island Power Authority 2019 Proposed and 2020 Projected Operating and Capital Budgets

Debt Service Requirements

Debt service consists of principal and interest payments due to bondholders. Debt service payments are broken out separately for UDSA debt and Authority debt. In prior years, the Authority refinanced debt through the UDSA, which resulted in a net savings to customers.

In addition to debt service payments, under the Public Power Model, the Authority also recovers “fixed obligation coverage.” Fixed obligation coverage is the portion of the Authority’s capital program funded by cash flow in each year rather than by new borrowings. Fixed obligation coverage is a ratio based on the Authority’s annual debt service payments and the imputed payments associated with long-term obligations such as power supply contracts and office and vehicle leases.

The 2015 DPS Rate Recommendation endorsed the financial policy proposed by the Authority in the Three-Year Rate Plan filing, which included several components:

- (i) **Public Power Model.** The Public Power Model used by nearly all of the country’s major public power entities recovers the Authority’s operating expenses in each year plus its debt service requirements (including fixed obligation coverage).
- (ii) **Mid-A Ratings Target Over Five Years.** At the time of the Rate Plan filing in 2015, the Authority had credit ratings of Baa1 (stable outlook), A- (negative outlook), and A- (negative outlook) (M/S/F), which were the lowest of any large public power utility by several credit categories. The adoption of the Public Power Model combined with the utility’s rate adjustment mechanisms, predictable cash flow, investments in operational and system improvements and positive customer service metrics resulted in a ratings upgrade by Moody’s to an A3 rating in August 2016. With the expectation for continued improvements, all three rating agencies have changed their outlooks since 2016. Moody’s and S&P’s outlook changed to Positive and Fitch’s outlook changed to Stable from Negative. These outlooks offer the potential for future improvements in the Authority’s credit ratings. As part of the rate plan, the Authority adopted a five-year rating target to improve its ratings to A2/A/A.

Long Island Power Authority and Subsidiaries 2019 Proposed and 2020 Projected Operating and Capital Budgets

- (iii) **Reduce Borrowings to No More than 64% of Capital Spending.** The Authority's "debt ratio" (defined as the percentage of debt in the Authority's capital structure to total debt plus net position) is higher than most utilities. This is a historical legacy. A ratio of 55-65% is typical for large public power utilities like the Authority, whereas the Authority's 2019 budgeted debt ratio is at 90.0% (see page 39).

The higher-than-average debt ratio is attributable to the debt incurred to acquire the electric system from its previous owner in 1998. That acquisition resulted in an approximate 20% reduction in customers' electric bills, a benefit that continues today. However, in order to reduce the debt ratio over time, the Authority has adopted a target to reduce borrowings in each year to no more than 64% of capital spending, with the balance funded by cash flow in lieu of new debt. This level is typical for large public power utilities and an industry best practice.

- (iv) **Increasing Fixed Obligation Coverage Targets.** To achieve the Authority's goals of improved credit ratings and reduced borrowings over five years, the Authority has achieved the fixed obligation coverage target in 2017 and expects to increase that target gradually as outlined in the table below. Given the Authority's two types of debt – Authority revenue bonds and UDSA securitization debt – the Authority adopted coverage ratios with and without UDSA bonds.

Minimum Fixed Obligation Coverage Ratios

<u>Fixed Obligations</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>
Authority Debt + Capitalized Leases	1.20 x	1.30 x	1.40 x	1.45 x
Authority Debt + UDSA Debt + Capitalized Leases	1.15 x	1.20 x	1.25 x	1.25 x

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

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Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Capital Expenditures (Thousands of Dollars)							
Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
Transmission and Distribution							
Regulatory Driven	\$ 3,016	\$ 8,130	\$ 5,212	\$ 25,489	\$ 17,359	\$ 85,500	\$ 60,011
Load Growth	169,382	188,668	138,443	262,030	73,362	253,323	(8,707)
Reliability	213,762	191,845	181,984	190,518	(1,327)	188,031	(2,486)
Economic, Salvage, Tools, Equipment & Other	26,884	34,569	37,082	48,866	14,297	34,173	(14,692)
Total Transmission and Distribution Projects	413,044	423,212	362,721	526,902	103,690	561,028	34,126
Other PSEG Long Island Capital Expenditures							
Information Technology	22,319	36,728	31,486	35,236	(1,492)	40,683	5,447
Customer Operations	16,405	11,394	14,433	11,394	-	11,259	(135)
Other General Plant	2,635	9,196	4,906	8,944	(252)	4,534	(4,410)
Fleet	20,137	8,526	9,296	5,495	(3,031)	10,735	5,240
Utility 2.0	-	12,975	12,769	69,661	56,686	54,158	(15,503)
Budget Amendment to Carryover	(a) -	(56,120)	-	-	56,120	-	-
Total PSEG Long Island Excluding FEMA	474,540	445,911	435,611	657,632	211,721	682,397	24,765
FEMA Related Projects	182,996	190,273	156,734	153,609	(36,664)	49,980	(103,629)
Storm Capitalization	-	-	-	3,501	3,501	4,243	742
Total PSEG Long Island Capital	657,536	636,184	592,345	814,742	178,558	736,620	(78,122)
Nine Mile Point 2	22,777	15,858	17,441	19,461	3,602	13,564	(5,896)
LIPA - Other	33	7,547	300	5,700	(1,847)	5,050	(650)
Allowance For Funds Used During Construction	(b) 5,904	7,874	4,182	-	(7,874)	-	-
Capitalized Management Fee	9,748	30,632	26,794	28,926	(1,706)	29,504	578
Total Capital Expenditures	695,998	698,095	641,062	868,829	170,734	784,739	(84,090)
FEMA Contribution (90% of Project Costs)	(c) (164,697)	(171,246)	(141,060)	(138,248)	32,997	(44,982)	93,266
Deduct Allowance For Funds Used During Construction	(b) 5,904	7,874	4,182	-	(7,874)	-	-
Net Capital Expenditures	525,397	518,976	495,820	730,581	211,605	739,757	9,176
Funding Available from Operations (Coverage)		194,340	203,405	218,305	23,965	239,369	21,064
Contribution to OPEB Fund from Revenue Requirements		(40,669)	(46,282)	(27,509)	13,160	(27,509)	-
Deduct Net Funding of Capital Expenditures		153,672	157,123	190,797	37,125	211,860	21,064
Funding Required from New Debt		\$ 365,305	\$ 338,697	\$ 539,784	\$ 174,480	\$ 527,896	\$ (11,888)

Note: (a) A Budget Amendment to Carryover specific projects in the amount of \$56.1 million from 2018 to 2019 is included in PSEG Long Island Excluding FEMA Capital of \$657.6 million.

(b) Due to a change in accounting treatment the Allowance For Funds Used During Construction is eliminated effective in 2019.

(c) Amounts not yet reimbursed by FEMA; pending completion of individual projects.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Capital Expenditures
(Thousands of Dollars)

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
Percent of Capital Funded from Debt:							
Including FEMA spending and reimbursement		52%	53%	62%		67%	
Excluding FEMA spending and reimbursement		68%	67%	73%		71%	

Reconciliation of Utility 2.0					
Utility 2.0 Approved Filing		\$ 15,475		\$ 71,961	
Utility 2.0 Budget Amendment (a)		(4,800)		-	
Utility 2.0 Meter Deployment Acceleration (2019 into 2018)		2,300		(2,300)	
Total Utility 2.0		\$ 12,975		\$ 69,661	

Note: (a) Subsequent to the DPS approval of the 2017 Utility 2.0 filing, the capital funding requirements for 2018 Utility 2.0 projects were reduced due to updated budget assumptions.

Major Projects

(Projects with a total cost greater than \$25 million)

Description	Justification	In Service Date	Cash Flow (\$millions)				
			Project To Date Expenditures through 12/31/18	2019	2020	2021 and Beyond	Total Project Cost
Malverne: Upgrade 69/13 kV substation & distribution feeder	Meet the load growth in the town of Malverne	2019	\$ 18.6	\$ 6.6	\$ -	\$ -	\$ 25.3
Southampton - Canal: Install new 69kV underground cable in an existing conduit	Meet the load growth in the South Fork	2019	\$ 7.9	\$ 20.0	\$ 0.1	\$ 1.6	\$ 29.5
Two Way Radio System Replacement: Replace existing VHF conventional radio system with new territory-wide radio system	Current system is a mix of legacy radio console, mobiles and portable radios with average age of equipment ranging from 10 to 35 years old that vendors no longer support	2019	\$ 23.1	\$ 12.4	\$ 3.5	\$ 8.7	\$ 47.7
Belmont New Substation: Install new 33/13kV substation & distribution feeder	Meet the load growth in Belmont Park	2020	\$ 1.1	\$ 19.4	\$ 23.7	\$ 7.0	\$ 51.3
East Garden City - Valley Stream: Install new 138kV underground cable	Meet new NERC reliability requirements	2020	\$ 7.8	\$ 25.5	\$ 85.5	\$ 58.1	\$ 176.9
Hempstead: Upgrade Existing Substation from 23/4 kV to 69/13 kV	Meet the load growth in the Town of Hempstead	2020	\$ 23.7	\$ 9.7	\$ 2.4	\$ 3.1	\$ 38.9
Lindbergh (formerly Nassau Hub): Construct new substation with 2 transformers and 6 new distribution feeders. Land purchase is required.	Meet the forecasted load growth for the Nassau Coliseum re-development which includes new: retail stores, restaurants, movie theaters and Police Academy	2020	\$ 6.4	\$ 25.0	\$ 7.3	\$ 26.1	\$ 64.8
Ruland Rd - Plainview: Construct new Underground 69kV transmission line	Meet the load growth to support the Country Pointe Development (commercial and residential) and the new Round Swamp Substation	2020	\$ 3.7	\$ 15.7	\$ 21.5	\$ 18.7	\$ 59.6
Berry St: Construct new substation with 2 transformers and 6 new distribution feeders	Meet the load growth in the towns of Farmingdale and Lindenhurst	2021	\$ 29.4	\$ 0.6	\$ 6.5	\$ 6.9	\$ 43.5
Bridgehampton - Buell: Install a new 69kV underground cable (approximately 5 miles)	Meet the load growth in the South Fork	2021	\$ 0.6	\$ 2.7	\$ 18.6	\$ 25.0	\$ 46.9
Kings Highway: Construct new substation with 3 transformers and 8 new distribution feeders	Meet the load growth in the towns of Smithtown, Hauppauge and Islip	2021	\$ 21.8	\$ 24.7	\$ 12.9	\$ 7.3	\$ 66.7
Navy Rd: Establish new 23/13 kV substation	Meet the load growth in Montauk	2021	\$ 7.7	\$ 7.7	\$ 7.9	\$ 11.5	\$ 34.7
Riverhead - Canal: Install new 138 kV underground cable	Meet the load growth in the South Fork	2021	\$ 0.2	\$ 7.6	\$ 41.4	\$ 56.1	\$ 105.2
Fire Island Pines: Install new 23 kV circuit to Ocean Beach	Increase reliability to Fire Island	2022	\$ 1.3	\$ 3.0	\$ 0.9	\$ 45.9	\$ 51.1
Massapequa: Establish new 69/13kV substation	Meet the load growth in the town of Massapequa	2022	\$ 0.2	\$ 2.1	\$ 8.0	\$ 21.4	\$ 31.8
Transmission Operations Control Room Facility Replacement: Replace the existing Transmission Operations control room in Hicksville with a new Primary Control Center to support the addition of new substations and elements that are continuously added to the system.	Upgrade control room to support addition of new substations	2023	\$ -	\$ 0.2	\$ 3.5	\$ 80.4	\$ 84.0
Substation Security Expansion Project	Enhance substation security	2023	\$ 0.8	\$ 1.3	\$ 0.5	\$ 54.2	\$ 56.8

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Capital Expenditures

Capital Expenditures are budgeted at \$868.8 million in 2019 and projected at \$784.7 million in 2020. Net Capital Expenditures are budgeted at \$730.6 million in 2019 and projected at \$739.8 million in 2020. The 2019 Capital Budget includes a deferral of certain specified 2018 Capital projects into 2019, as shown on pages 48 and 49.

Transmission and Distribution projects are evaluated using a Project Prioritization and Value and Risk Evaluation protocol using the Spend Optimization Suite to determine the projects that have the highest risk for system and company performance. The projects being pursued will improve system reliability and resiliency and include increases from historical spending on the Circuit Improvement Program to address poor performing circuits and the Multiple Customer Outage Program to address customers that experience an unusual number of outages.

In February 2014, the Authority signed a Letter of Undertaking with FEMA that provides for a \$730.0 million storm hardening initiative. As part of this program, FEMA will contribute 90% of the cost to this project.

Information Technology projects include improvements and upgrades to systems that support Transmission and Distribution, Customer Services and Security.

Capital expenditures for Customer Services are primarily comprised of costs associated with residential and commercial meter replacement.

Capital expenditures for 2019 and 2020 include additional costs related to the Utility 2.0 Plan. These costs are associated with projects aimed at smart meters and integrating Distributed Energy Resources (DER) in the Authority's electric grid.

Nine Mile Point 2 Capital Expenditures relates to the Authority's share of capital expenses for the NMP2 nuclear generating station of which the Authority owns an undivided 18% interest in one of two nuclear units. These expenditures include cost for capital improvements to the facility and the cost of nuclear fuel.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Appendix

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

PSEG Long Island Operating Expenses
(Thousands of Dollars)

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
PSEG Long Island Operating Expenses (including Pension & OPEB) (a)							
Transmission & Distribution	\$ 210,510	\$ 181,832	\$ 189,580	\$ 177,615	\$ (4,217)	\$ 181,542	\$ 3,927
Customer Services	118,845	125,619	129,906	126,620	1,000	128,355	1,735
Business Services	131,949	162,824	166,820	170,975	8,151	170,975	-
Power Markets	8,671	14,373	11,374	14,156	(217)	14,156	-
Energy Efficiency & Renewable	82,652	88,794	82,086	88,794	-	88,794	-
Utility 2.0 Costs	-	4,262	3,227	19,237	14,975	18,503	(734)
Utility 2.0 Savings	-	-	-	(2,878)	(2,878)	(6,858)	(3,980)
Budget Amendment to Carryover (b)	-	(724)	-	-	724	-	-
Total PSEG Long Island Operating Expenses	552,627	576,981	582,993	594,519	17,538	595,468	949
Total Non Cash OPEB Expense (c)	41,080	40,669	49,284	43,955	3,286	44,934	979

Note: (a) Due to the 2018 reorganization, the budgeted amounts were reallocated from what was approved in the prior year budget document.

(b) The Budget Amendment to Carry over of \$0.7 million is related to the Utility 2.0 Super Saver program.

(c) Non Cash cost of Other Post Retirement Benefits (OPEB) included in operating expenses above.

Long Island Power Authority 2019 Proposed and 2020 Projected Operating and Capital Budgets

PSEG Long Island Operating Expenses

PSEG Long Island Operating Expenses are related to five major areas: Transmission and Distribution, Customer Services, Business Services, Power Markets and Energy Efficiency and Renewable Energy Programs. Total operating expenses are budgeted at \$594.5 million for 2019 and projected at \$595.5 million for 2020.

The approved operating expenses for 2018 have been decreased by \$0.7 million for 2019 carryover projects related to Utility 2.0. Total operating expenses for 2019 will remain the same, however, budgeted amounts may shift between various lines of business.

The PSEG Long Island 2019 operating budget, excluding the Utility 2.0 Program, is increasing by \$4.7M based on \$14.3M in expected inflationary costs, which is partially offset by (\$9.6M) of productivity savings.

Description	Net Change
Utility 2.0 Program, Net of savings (includes Carry Over of 2018 Super Saver Program)	\$12.8M
Expected Inflationary Cost	\$14.3M
PSEG Long Island Productivity Savings	(\$9.6M)
Total	\$17.5M

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

LIPA Operating & Deferred Expenses
(Thousands of Dollars)

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
LIPA Operating Expenses							
PSEG Long Island Management Fee	\$ 72,565	\$ 74,604	\$ 74,102	\$ 75,584	\$ 980	\$ 77,095	\$ 1,511
Capitalized Management Fee (a)	(9,748)	(30,632)	(26,794)	(28,926)	1,706	(29,504)	(578)
Total Operating Management Fee	62,817	43,972	47,307	46,658	2,686	47,591	933
LIPA Operating Expenses							
Employee Salaries & Benefits Expenses	8,040	11,151	9,455	11,125	(26)	11,262	137
Insurance	1,842	2,060	1,696	2,904	844	2,985	81
Office Rent	1,703	1,737	1,757	1,811	74	1,812	1
Miscellaneous	6,416	2,955	2,299	2,696	(259)	2,755	59
Total Labor, General and Administrative	18,001	17,903	15,206	18,536	633	18,814	278
Engineering	243	1,533	433	1,000	(533)	1,073	73
Legal	5,208	4,500	7,129	7,845	3,345	8,022	177
Financial Services and Cash Management	1,868	1,860	2,131	4,090	2,230	4,182	92
Accounting and Audit Services	1,439	1,770	2,088	1,840	70	1,882	41
Information Technology	842	633	850	1,995	1,362	2,040	45
Risk Management	567	465	366	335	(130)	343	8
Grant Administration	312	200	203	200	(0)	200	-
Miscellaneous	2,036	4,177	2,367	1,120	(3,057)	1,145	25
Total Professional Services	12,515	15,138	15,566	18,425	3,288	18,886	460
LIPA Operating Expenses	93,333	77,012	78,080	83,619	6,607	85,290	1,671
Amortization of OPEB & Pension Deferrals	31,014	31,015	31,015	25,015	(6,000)	25,015	-
Total LIPA Operating and Deferred Expenses	\$ 124,348	\$ 108,027	\$ 109,095	\$ 108,634	\$ 607	\$ 110,305	\$ 1,671

Note: (a) Effective in 2018, a new methodology based on the PSEG Long Island company labor allocation was adopted to determine the Capitalized Management Fee. As a result the portion of the management fee allocated to capital increased from (\$9.7M) in 2017 to (\$30.6M) in 2018.

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

LIPA Operating and Deferred Expenses

The Authority Operating and Deferred Expenses are budgeted at \$108.6 million in 2019 and projected at \$110.3 million in 2020. The 2019 plan represents an increase of \$0.6 million as compared with the Approved Budget for 2018.

LIPA Operating and Deferred Expenses include the PSEG Long Island management fee, costs related to Authority staff and outside professional services, and the amortization of certain regulatory assets.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Utility Debt Securitization Authority
(Thousands of Dollars)

Description	2017	2018		2019		2020	
	Actual	Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
Revenues	\$ 297,679	\$ 330,276	\$ 330,230	\$ 332,694	\$ 2,419	\$ 324,599	\$ (8,095)
Operating Expenses							
Uncollectible Accounts	1,345	2,213	2,015	2,029	(183)	1,980	(49)
General and Administrative Expense							
Ongoing Servicer Fees	2,146	2,265	2,250	2,250	(15)	2,250	-
Administration Fees	417	500	500	500	-	500	-
Bond Administration Fees	246	250	340	300	50	300	-
Bond Trustee Fees and Expenses	-	70	-	-	(70)	-	-
Legal Fees	5	40	-	-	(40)	-	-
Accounting Fees	135	165	150	150	(15)	200	50
Directors and Officers Insurance	303	410	267	325	(85)	339	14
Miscellaneous	2	32	-	-	(32)	-	-
Total General and Administrative Expense	3,254	3,732	3,507	3,525	(207)	3,589	64
Amortization of Restructuring Property	117,844	166,440	165,533	174,401	7,961	169,993	(4,408)
Interest Expense Accrual	187,163	201,528	200,495	196,248	(5,280)	192,041	(4,207)
Amortization of Premium	(43,663)	(45,918)	(46,136)	(44,779)	1,139	(45,706)	(927)
Amortization of Deferred Debt Issue Costs	2,465	2,518	2,521	2,361	(156)	2,200	(161)
Total Interest Expense	145,965	158,127	156,879	153,831	(4,297)	148,535	(5,295)
Reserve Fund Earnings	989	550	2,306	1,164	614	1,136	(28)
Excess of Revenues Over Expenses	\$ 30,259	\$ 313	\$ 4,601	\$ 73	\$ (241)	\$ 1,638	\$ 1,565

Long Island Power Authority 2019 Proposed and 2020 Projected Operating and Capital Budgets

Utility Debt Securitization Authority

The LIPA Reform Act, as amended, created the Utility Debt Securitization Authority (UDSA) to issue restructuring bonds in an aggregate amount not to exceed \$4.5 billion to refinance a portion of the Authority's existing debt at a lower cost. The UDSA has no commercial operations and was formed solely to issue bonds to refinance Authority debt. The UDSA has bond ratings of Aaa(sf), AAA(sf) and AAA(sf) from Moody's, Standard & Poor's and Fitch Ratings, respectively, compared to ratings of A3, A-, and A-, respectively, for Authority issued bonds.

The Authority issued approximately \$2.0 billion of UDSA bonds in 2013, \$1.0 billion in October 2015, two additional series totaling an additional \$1.1 billion in 2016, and \$369.5 million in 2017.

The Authority's customer bills recover UDSA Restructuring Charges (consisting of debt service and administrative fees) on every kilowatt hour of energy delivered and the Authority's own delivery charges are reduced by an amount that corresponds to the UDSA charges in each period; however, the UDSA charges are not Revenues subject to the Authority's bond resolutions.

The UDSA's revenues and expenses are consolidated with those of the Authority for financial reporting purposes; and therefore the information on UDSA presented herein is also reflected within the categories of revenue and expense of the Authority's Operating Budgets shown elsewhere. This supplemental page is shown separately as an information item for the reader.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Projected Borrowing Requirements and Bank Facilities
(Thousands of Dollars)

Description	2017 Actual	2018		2019		2020	
		Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
Total Capital Expenditures	(a) \$ 695,998	\$ 698,095	\$ 641,062	\$ 868,829	\$ 170,734	\$ 784,739	\$ (84,090)
FEMA Contribution	(164,697)	(171,246)	(141,060)	(138,248)	32,997	(44,982)	93,266
Deduct Allowance for AFUDC	(b) (5,904)	(7,874)	(4,182)	-	7,874	-	-
Net Capital Expenditures	525,397	518,976	495,820	730,581	211,605	739,757	9,176
Net Coverage Funding of Capital Expenditures	(183,174)	(153,672)	(157,123)	(190,797)	(37,125)	(211,860)	(21,064)
Proceeds for Carry Over Projects	6,036	-	89,163	-	-	-	-
Projected Borrowing Requirements	348,259	365,305	427,860	539,784	174,480	527,896	(11,888)
Projected Cost of Issuance on Borrowing Requirements	1,741	1,827	2,139	2,699	872	2,639	(59)
Projected Borrowing Requirements with Cost of Issuance	(c) 350,000	367,131	430,000	542,483	175,352	530,536	(11,947)
Series 2014C - Floating Rate Notes	-	150,000	150,000	-	(150,000)	-	-
Series 2015C - Floating Rate Notes	-	149,000	149,000	-	(149,000)	-	-
Series 2016A - Floating Rate Notes	-	-	-	-	-	-	-
General Revenue Notes, Series 2015	-	75,000	75,000	100,000	25,000	100,000	-
Revolving Credit Agreement	-	-	-	350,000	350,000	-	(350,000)
Bonds Subject to Mandatory Refinancing & Bank Facilities	\$ -	\$ 374,000	\$ 374,000	\$ 450,000	\$ 76,000	\$ 100,000	\$ (350,000)

Note: (a) This reflects a Budget Amendment to Carryover specific projects in the amount of \$56.1 million from 2018 to 2019.

(b) Due to a change in a new accounting treatment Allowance For Funds Used During Construction (AFUDC) is eliminated effective in 2019.

(c) Excludes premium, if generated it would reduce short term borrowing.

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

Projected Borrowing Requirements and Bank Facilities

The Authority expects to generate funds from operations of \$190.8 million and \$211.9 million in 2019 and 2020, respectively. The balance of the Capital Budget will be funded from the issuance of debt. In total, the Authority will fund \$868.8 million of infrastructure investments in 2019 with new debt issuances of \$542.5 million or approximately 62% debt financing and 38% grant and pay-as-you-go funding.

Long Island Power Authority
2019 Proposed and 2020 Projected Budgets

Capital Structure
(Thousands of Dollars)

Description	2017 Actual	2018		2019		2020	
		Approved	Projected	Proposed	Change from Prior Year	Projected	Change from Prior Year
UDSA Long Term Par Outstanding	\$ 4,262,396	\$ 4,139,593	\$ 4,139,593	\$ 4,008,832	\$ (130,761)	\$ 3,882,775	\$ (126,057)
LIPA Long Term Par Outstanding	2,864,214	3,167,465	3,167,465	3,557,872	390,407	4,021,701	463,829
LIPA Short Term Par Balance	360,320	400,000	334,500	334,500	(65,500)	334,500	-
Total Par Outstanding	7,486,930	7,707,058	7,641,558	7,901,204	194,146	8,238,976	337,772
LIPA Long Term Par To Be Issued	350,000	367,131	430,000	542,483	175,352	530,536	(11,947)
Par Amount UDSA	4,262,396	4,139,593	4,139,593	4,008,832	(130,761)	3,882,775	(126,057)
Par Amount LIPA	3,574,534	3,934,596	3,931,965	4,434,855	500,259	4,886,736	451,881
Total Par Amount	7,836,930	8,074,189	8,071,558	8,443,687	369,498	8,769,511	325,824
Capital Lease Obligations (a)	1,843,515	1,824,665	1,824,665	1,660,829	(163,836)	1,493,746	(167,083)
Total Par and Capital Lease Obligations	9,680,445	9,898,854	9,896,222	10,104,516	205,662	10,263,257	158,741
Excess of Revenues Over Expenses	17,122	1,100	2,122	(4,424)	(5,524)	34,197	38,621
Net Position Before Deferred Grants	472,188	462,899	474,310	469,885	6,987	504,083	34,197
Deferred Grants (b)	501,404	497,836	498,536	648,095	150,259	637,592	(10,503)
Net Position	\$ 973,592	\$ 960,735	\$ 972,846	\$ 1,117,980	\$ 157,246	\$ 1,141,675	\$ 23,694
Debt to Capital Ratio (c)	90.9%	91.2%	91.0%	90.0%		90.0%	
Debt to Asset Ratio (c)	105.2%	102.0%	97.3%	93.4%		90.5%	

A

B

C=A/(A+B)

Note: (a) The 2020 Capital Lease and Long-term Obligation amounts and the associated Coverage calculation do not reflect GASB No. 87 (Leases) implementation.

(b) Deferred Grants are funds received from FEMA for a \$730.0 million storm hardening program. LIPA has deferred recognition of the grant income to align the grant receipts with the associated depreciation expense.

(c) Debt to Capital Ratio is calculated by taking (i) debt and capitalized leases and dividing by (ii) debt, capitalized leases, and Net Position.
Debt to Asset Ratio is calculated by taking (i) total debt and capitalized leases and dividing by (ii) fixed assets and working capital.

2019 Proposed and 2020 Projected Operating and Capital Budgets

Capital Structure

The Capital Structure shows the ratio of debt and net position. LIPA expects to fund its capital investment program utilizing a combination of pay-as-you-go funding from revenue, grants, and short and long-term debt financing through 2020.

After funding \$3.0 billion in infrastructure investments from 2017 through 2020, total projected debt outstanding for LIPA and UDSA will rise approximately \$932.6 million.

The Authority has significant capital lease obligation amortization during this period with total capital leases declining by \$350 million. Combined debt and capital lease balances across the period increase from \$9.7 billion at the end of 2017 to \$10.3 billion at the end of 2020. The Authority's Debt to Capital Ratio improves modestly from 90.9% in 2017 to 90.0% in 2020 while the Debt to Asset Ratio declines from 105.2% in 2017 to 90.5% in 2020.

2019 Proposed and 2020 Projected Capital Expenditures
(Thousands of Dollars)

	Location	Investment Description	In Service Date	Total Project Cost	Project To Date Expenditures through 12/31/18 (a)	Proposed 2019	Projected 2020
Transmission & Distribution							
Regulatory Driven Projects							
	East Garden City	EGC- Valley Stream (N-1-1)	Dec-20	176,944	7,840	25,489 *	85,500
Total Regulatory Driven Projects				\$ 176,944	\$ 7,840	\$ 25,489	\$ 85,500
Load Growth Projects							
	West Bartlett	Establish new 69/13 kV substation	May-18	17,118	17,018	100	-
	Terryville	Conversion and reinforcement and exit feeder projects	Dec-18	2,394	1,817	577	-
	Sterling	Install new distribution feeder	Jun-19	5,250	100	5,150	-
	Malverne	Upgrade 69/13 kV substation & distribution feeder	Jun-19	25,281	18,636	6,645	-
	Pilgrim	Replace 13kV switchgear & install new feeder	Jun-19	9,499	5,240	4,259 *	-
	Southampton	Install new 69kV circuit to Canal	Jun-19	29,536	7,867	20,019 *	78
	Arverne	Underground 13kV feeder extension	Jun-19	4,851	2,171	2,680 *	-
	Park Place	Conversion and reinforcement and exit feeder projects	Jun-19	10,825	4,675	6,150	-
	Massapequa	New substation land acquisition	Aug-19	2,300	-	2,300	-
	Montauk	Land acquisition Montauk replacement substation	Sep-19	6,025	67	5,959	-
	Riverhead	Install new 13kV circuit	Dec-19	1,038	-	831	78
	Lake Success	Smart Wires - Lake Success to Stewart Manor to Whiteside	Dec-19	9,650	144	8,377 *	220
	Malverne	Reconfigure distribution circuits to Valley Stream	Dec-19	3,732	100	2,637	200
	Flowerfield	Upgrade 69/13 kV substation & distribution feeder	Jun-20	19,433	387	7,683 *	9,007
	MacArthur	Install 27 MVAR Capacitor Bank	Jun-20	2,663	1,284	395	701
	Round Swamp	Establish new 69/13kV substation	Jun-20	20,486	4,036	5,540 *	7,624
	Ruland Road	Install new 69 kV circuit to Plainview	Jun-20	59,571	3,659	15,710 *	21,487
	Hero	Upgrade substation from 23 kV to 33 kV	Jun-20	694	23	24 *	152
	Belmont	Establish new 33/13kV substation	Jun-20	51,261	1,120	19,430	23,684
	Kings Highway	Establish new 138/13 kV substation	Jun-20	66,651	21,786	24,660 *	12,928
	Hempstead	Convert station to 69/13 kV	Dec-20	38,885	23,715	9,677	2,415
	Roslyn	Expand 138/13 kV substation and feeders	Dec-20	13,942	1,256	3,650 *	6,820
	Deer Park	Install 27 MVAR Capacitor Bank	Jun-21	2,432	1,002	100	350
	Ronkonkoma	Install new 138/69 kV transformer and switchgear	Jun-21	15,300	-	625	9,675
	New South Road	Expand 69/13kV substation & distribution cables	Jun-21	17,903	2,803	2,220	4,440
	Berry Street	Establish new 69/13 kV substation and upgrade 69kV transmission lines	Jun-21	43,461	29,435	574	6,539
	Navy Road	Establish new 23/13 kV substation (Montauk substation replacement)	Jun-21	34,730	7,682	7,650 *	7,925
	Wildwood	Upgrade 69 kV circuit to Riverhead to 138 kV	Jun-21	11,191	138	249	5,686
	Bridgehampton	Install new 69kV circuit to Buell	Jun-21	46,917	556	2,705 *	18,648
	Riverhead	Install new 138 kV circuit to Canal	Jun-21	105,189	165	7,600	41,350
	Culloden Point	Upgrade substation from 23 kV to 33 kV	Jun-21	7,000	65	1,392 *	1,753
	South Fork	Upgrade transmission lines from 23 kV to 33 kV	Jun-21	1,100	39	200	400
	Ocean Beach	Install new 4kV feeder	Jun-22	3,750	-	200	400
	Lindbergh	Establish new 69/13kV substation	Jun-22	64,827	6,359	25,015	7,335
	Massapequa	Establish new 69/13kV substation	Jun-22	31,790	189	2,140 *	8,022
	East Hampton	Upgrade substation from 23 kV to 33 kV	Jun-22	5,100	45	1,050	300
	Buell	Upgrade substation from 23 kV to 33 kV	Jun-22	11,625	60	1,514	1,651
	Amagansett	Upgrade substation from 23 kV to 33 kV	Jun-22	17,090	168	5,779	2,460
	Peconic	Upgrade existing distribution banks	Dec-22	7,000	-	-	350
	Hither Hills	Upgrade substation from 23 kV to 33 kV	Jun-23	15,278	40	1,851	3,862
	Various	Distribution facilities to serve new business	Blanket	-	37,098	36,713	36,185
	Various	Residential underground development to serve new business	Blanket	-	12,060	12,000	10,600
Total Load Growth Projects				\$ 842,768	\$ 213,003	\$ 262,030	\$ 253,323
Reliability Projects							
	Lake Success	Phase Angle Regulator (PAR)	Dec-17	3,684	3,440	244	-
	Shelter Island	Replace underground failed cable	Jun-18	18,983	18,883	100	-
	Island Park	Reconfigure transmission 33kV circuits	Dec-18	2,781	2,631	150	-
	Various	Upgrade substation breaker controls for Non-Reclosure Assurance (NRA)	Dec-18	17,283	16,883	400	-

* Includes carry over from 2018. See "Carry Over" table for details

(a) Project to date expenditures includes projects that began prior to 2018

2019 Proposed and 2020 Projected Capital Expenditures
(Thousands of Dollars)

Location	Investment Description	In Service Date	Total Project Cost	Project To Date Expenditures through 12/31/18 (a)	Proposed 2019	Projected 2020
Valley Stream	Replace Phase Angle Regulator (PAR) transformer	Dec-18	4,026	3,526	500	-
Various	Telecom connectivity and radio room upgrades	Apr-19	175	-	175	-
Elwood	Install bus tie breaker	Jun-19	3,307	2,889	418	-
Far Rockaway	Storm hardening 33kV substation (damaged by Sandy)	Jun-19	13,292	10,952	2,340	-
Rockaway Beach	Install new battery house and elevate batteries	Jun-19	690	370	320	-
Valley Stream	Corrosion protection system upgrade for feeder 138-901	Jun-19	1,560	224	1,336	-
Hicksville	Upgrade monitoring and alarm system for the oil storage areas	Jul-19	200	-	200	-
Various	Telecom alarm monitoring system	Sep-19	200	-	200	-
Hewlett	Upgrade copper to fiber for distribution automation	Nov-19	270	-	270	-
Barrett	Procure new spare 220 MVA phase shifter transformer	Dec-19	8,000	2,167	5,833	-
Hicksville	Purchase two mobile units	Dec-19	3,295	170	3,125 *	-
Northport	Phase shifter replacement load tap changer controls	Dec-19	500	-	500	-
Various	Telecom communication cabinets upgrade	Dec-19	465	-	465	-
Glenwood	Feeder 69-477 terminal alarms	Dec-19	201	81	120	-
Fire Island Pines	Install new 23 kV circuit to Davis Park	Jun-20	4,226	1,054	1,386 *	1,140
Far Rockaway	Land rights acquisition (Phase 2)	Dec-20	8,169	7,343	-	826
Various	Upgrade corrosion protection system for pipe type cable	Dec-21	17,500	-	4,500	4,000
Fire Island Pines	Install new 23 kV circuit to Ocean Beach	Jun-22	51,135	1,322	3,007 *	886
East Garden City	Switchgear replacement	Dec-22	14,450	-	250	5,193
Northport	Replace radiators for banks 1 to 4	Dec-23	7,040	-	1,040	1,680
Various	Substation rack replacement	Dec-25	36,600	-	100	1,500
Various	Distribution system improvements - services, branch lines & customer requests	Program	-	13,220	16,000	14,500
Various	Distribution breaker replacement program	Program	-	473	745	745
Various	Underground distribution cable upgrade program	Program	-	9,170	13,000	10,200
Various	Distribution protection and controls upgrade program	Program	-	-	486	410
Various	Mechanical relay replacement program	Program	-	336	1,171	1,245
Various	Pipe type cable low pressure trip program	Program	-	418	1,326	1,366
Various	Pipe type cable terminal pressure monitoring upgrade program	Program	-	676	1,446	-
Various	Protection lease line upgrades	Program	-	855	1,400	1,600
Various	Replacement of aging and non-functional Joslyn type ASUs	Program	-	1,887	3,000	3,200
Various	Remote terminal unit replacement/upgrade program	Program	-	399	1,262	1,362
Various	Substation battery replacement program	Program	-	464	468	482
Various	Protection and controls upgrade program	Program	-	700	1,045	1,100
Various	Substation control power transformer replacement program	Program	-	-	262	262
Various	Transfer trip/SCADA communication network upgrade program	Program	-	-	200	200
Various	Transformer major component replacement program	Program	-	724	504	720
Various	Transformer monitoring program	Program	-	(3)	950	950
Various	Transmission breaker replacement program	Program	-	1,067	2,500	2,700
Various	Transmission cables cathodic replacement program	Program	-	187	363	374
Various	Update substation distribution breaker racking system	Program	-	709	1,000	1,050
Various	Substation lightning & grounding upgrade program	Program	-	208	790	790
Various	Upgrade supervisory controllers for Capacitor Banks	Program	-	499	491	2,213
Various	Distribution storm hardening program - install communication repeaters	Program	-	-	3,500	10,000
Various	Transformer load tap changer replacements	Program	-	600	486	410
Various	Distribution automation repeater upgrades	Blanket	-	-	248	-
Various	Accidents	Blanket	-	11,969	10,208	10,446
Various	Cap and pin insulator replacement program	Program	-	-	158	175
Various	Distribution feeder reliability improvement program (Minor Extensions)	Blanket	-	25,043	25,966	26,454
Various	Distribution pole reinforcement	Blanket	-	3,852	2,202	2,570
Various	Distribution pole replacements	Blanket	-	13,609	13,518	13,935
Various	Substation equipment failures	Blanket	-	7,005	3,690	2,726
Various	Distribution transformers - add/replace	Blanket	-	23,889	18,305	18,128
Various	Multiple customer outage program	Blanket	-	5,518	7,677	7,060
Various	Public works	Blanket	-	8,500	7,623	8,793
Various	Transmission pole replacement	Blanket	-	807	1,599	1,866
Various	Residential underground cable program	Blanket	-	3,942	7,747	10,904
Various	System spares	Blanket	-	3,596	9,425	10,769
Various	Transmission system failures	Blanket	-	1,002	1,920	2,240
Various	Transmission pipe type cable pump house	Program	-	1,336	860	860
Total Reliability Projects			\$ 218,032	\$ 214,590	\$ 190,518	\$ 188,031

* Includes carry over from 2018. See "Carry Over" table for details

(a) Project to date expenditures includes projects that began prior to 2018

2019 Proposed and 2020 Projected Capital Expenditures
(Thousands of Dollars)

Location	Investment Description	In Service Date	Total Project Cost	Project To Date Expenditures through 12/31/18 (a)	Proposed 2019	Projected 2020
Tools, Equipment, Other, Economic, Salvage						
Various	Two way radio system upgrade project	Dec-19	47,668	23,061	12,388	3,500
Farmingville	Bald Hill repeater cabinet upgrade	Dec-19	85	-	85	-
Hicksville	Electrical shop building - door replacement	Jun-20	608	8	200	400
Jones Beach	Jones Beach Energy & Nature Center	Dec-20	9,000	-	3,500	3,500
Hicksville	Transmission operations control room facility replacement	May-23	84,000	-	150	3,500
Various	LIRR program	Program	-	1,916	1,000	1,000
Various	Feeder relay upgrade	Program	-	176	494	500
Various	Substation security upgrade project	Program	-	832	1,252	500
Various	Long Island Railroad right of way transmission pole replacement program	Program	-	12,541	19,270	9,040
Various	Dusk to dawn lighting	Blanket	-	645	3,403	5,822
Various	Eye wash station additions	Blanket	-	-	-	100
Various	Capital tools	Blanket	-	3,249	2,880	3,200
Various	Transfer distribution facilities to new telephone poles	Blanket	-	3,277	3,524	3,112
Hicksville	Transmission control room - map board MUX	Blanket	-	-	720	-
Total Tools, Equipment, Other, Economic, Salvage			\$ 141,361	\$ 45,706	\$ 48,866	\$ 34,173
Grand Total Transmission & Distribution			\$ 1,379,105	\$ 481,138	\$ 526,902	\$ 561,028

* Includes carry over from 2018. See "Carry Over" table for details

(a) Project to date expenditures includes projects that began prior to 2018

2019 Proposed and 2020 Projected Capital Expenditures
(Thousands of Dollars)

Information Technology Projects by Business Unit	Investment Description	In Service Date	Total Project Cost	Project To Date Expenditures through 12/31/18 (a)	Proposed 2019	Projected 2020
Transmission & Distribution	LI SCADA Network Upgrade to MPLS	2019	9,542	6,035	3,507	-
	DSCADA	2019	6,231	2,079	4,152 *	-
	CGI CAD Upgrade	2019	12,908	10,288	2,620 *	-
	EMS Upgrade LCP	2019	6,373	1,582	4,791 *	-
	Storm Damage Assessment & Repair Mobile App	2019	2,108	1,148	960	-
	New Business/BRS	2019	627	369	258 *	-
	T&D Mobile App Continuous Improvement & New Features	2020	Blanket	-	-	1,200
	Transformer Monitoring and Data collection in T&D - Transformers	2020	Blanket	-	-	950
	NERC Compliance Protection test records Database for document and process control	2020	750	-	-	750
	Transmission Control Charts Replacement and ACC solution required	2020	500	-	-	500
	TOA Application for Transmission Ops	2020	300	-	-	300
	Mutual Aid crew management and Storm Dashboard	2020	500	-	-	500
	CYME Interfaces and connectivity	2020	250	-	-	250
	GIS Field Smart Designer (AUTP)	2021	4,000	-	-	2,200
	Team Center Upgrade	2020	2,200	-	-	2,200
	OMS Enhancements and work management continuous improvement	2020	Blanket	-	-	500
	Distribution Automation Database Replacement	2020	400	-	-	400
	Telecom DA Repeater Site JMUX Upgrade	2020	Blanket	-	-	400
	P6 Analytics Portfolio Dashboard Reporting and risk scenarios Solution	2021	1,500	-	-	750
	Drone Vegetation management and LIRR Inspections	2020	Blanket	-	-	500
	Relay and Substation database consolidation and reports	2021	850	-	-	600
	Electric Service Database Consolidation and reports	2021	850	-	-	600
	Automatic upload to NJUNS	2020	650	-	-	650
	T&D Data Lake & Analytics	2020	Blanket	-	-	750
	GIS Validation	2021	950	-	-	450
	T&D Training technologies Virtual Reality/Augmented Reality	2023	2,000	-	-	500
	GIS Upgrade	2023	9,250	-	-	750
	Primavera Upgrade	2022	4,000	-	-	1,500
Total Transmission & Distribution			\$ 66,739	\$ 21,501	\$ 16,288	\$ 17,200
Customer Service	Customer 360/ Customer Analytics	2019	Blanket	-	1,360 *	-
	Customer 360/ Customer Analytics Enhancements Blanket	2020	Blanket	-	-	2,000
	CRM Modernization - Salesforce	2020	11,834	1,617	7,217 *	3,000
	Salesforce Continuous Improvement Program	2020	Blanket	-	-	1,000
	Rate Change 2018 and VDER	2019	548	474	74	-
	Rate Change Enhancements Blanket	2020	Blanket	-	-	750
	Mobile App	2019	1,194	294	900	-
	Mobile App Enhancements Blanket	2020	Blanket	-	-	500
	Pinpoint Project to Eliminate SSNs	2019	1,253	408	845 *	-
	New Business Portal	2019	842	190	652 *	-
	myAccount Enhancement Blanket	2019	Blanket	1,811	1,000	1,500
	Interactive Voice Response (IVR) Blanket (Continuous Improvement)	2019	Blanket	823	1,000	750
	Call Center Technology	2020	Blanket	-	-	1,000
	Enhance / New Payment Processing Options	2022	3,098	-	-	1,000
	Collection CAS Continuous Improvement Program	2020	Blanket	-	-	500
	AMI System Enhancements Continuous Improvement Program	2020	Blanket	-	-	1,431
	Voice Assistant (Multi channel)	2020	Blanket	-	-	500
	Kubra Enhancement Continuous Improvement Program	2020	Blanket	-	-	750
	Robotic Process Automation	2020	Blanket	-	-	250
	CAS Continuous Improvement	2020	Blanket	-	-	500
	Call Center LCP Software Upgrades	2020	Blanket	-	-	500
Total Customer Service			\$ 18,769	\$ 5,617	\$ 13,048	\$ 15,931

2019 Proposed and 2020 Projected Capital Expenditures
(Thousands of Dollars)

Information Technology Projects by Business Unit	Investment Description	In Service Date	Total Project Cost	Project To Date Expenditures through 12/31/18 (a)	Proposed 2019	Projected 2020
Information Technology	IT Life Cycle Replacement Program - CICS DB2	2019	759	409	350	-
	Middleware Upgrade/Replacement	2020	3,500	-	1,000	2,500
	AWS Migration - Cloud-based Storage Implementation (Gateway)	2019	500	-	500	-
	AWS Migration - Cloud-based Storage Implementation (Gateway) Enhancements Blanket	Blanket	Blanket	-	-	600
	AWS Migration - Standup AWS DMZ	2019	500	-	500	-
	Oracle 11.2 end of life - Replace with Open Source	2020	949	-	449	500
	Data Storage Refresh/Replacement - Non-Mainframe Systems	2019	500	-	500	-
	Network - Life Cycle Plan to Replace Aging Firewalls and Routers Part A	2019	600	449	151	-
	Infrastructure LCP	Blanket	Blanket	-	-	502
	LCP - Laptops	2019	1,100	350	750 *	-
	LCP - Mobile Data Terminals (MDTs)	2019	1,774	74	1,700 *	-
	LI LAN - NAC	2022	1,700	-	-	500
	LI WAN - LCP to Upgrade AWS Testing Toolkit	Blanket	1,300	-	-	500
	LI LAN - ISE (Identity Service Engine)	Blanket	3,225	-	-	500
	LI LAN - Upgrade Infrastructure Support Tools	Blanket	2,900	-	-	500
	LI WAN - Internet Upgrade	Blanket	350	-	-	250
	Okta - Identity Access for employees and applications	Blanket	2,000	-	-	300
	LI WAN - Copper to Fiber Network Transformation	Blanket	700	-	-	100
	LI WAN - WAN Diversity & SDWAN Implementation	2021	2,000	-	-	500
	LI LAN - Stealthwatch and DNAC integration	2020	300	-	-	300
Total Information Technology			\$ 24,657	\$ 1,282	\$ 5,900	\$ 7,552
Grand Total Information Technology Projects			\$ 110,165	\$ 28,400	\$ 35,236	\$ 40,683

* Includes carry over from 2018. See "Carry Over" table for details

(a) Project to date expenditures includes projects that began prior to 2018

**2019 Proposed and 2020 Projected Capital Expenditures
(Thousands of Dollars)**

Utility 2.0	Investment Description	Proposed 2019	Projected 2020
Empowering Customers			
	Core AMI: Operational	50,061	47,788
	Core AMI: PMO + Change Management	2,000	2,000
	Enabled AMI: Revenue Protection	1,050	-
	Enabled AMI: Customer Experience	3,300	1,500
	Enabled AMI: Outage Management	950	-
	Enabled AMI: Rate Modernization	9,500	-
	Enabled AMI: Analytics	4,100	600
	Accelerated Meters to 2018	(2,300)	-
Total Empowering Customers		\$ 68,661	\$ 51,888
Evolving to the DSP			
	SGIP Interconnection	-	2,270
	Locational Value Study	1,000	-
	NWA Planning & Analysis Tool	-	-
Total Evolving to the DSP		\$ 1,000	\$ 2,270
Total Utility 2.0 Projects		\$ 69,661	\$ 54,158

* Includes carry over from 2018. See "Carry Over" table for details
(a) Project to date expenditures includes projects that began prior to 2018

2019 Proposed and 2020 Projected Capital Expenditures
(Thousands of Dollars)

Business Units	Investment Description	In Service Date	Total Project Cost	Project To Date Expenditures through 12/31/18 ^(a)	Proposed 2019	Projected 2020
Customer Service						
	Purchase Electric Meters	Blanket	-	8,629	6,915	6,966
	Install/Remove Meters	Blanket	-	8,218	3,750	3,793
	Tools/Equipment	Program	-	1,667	729	500
Total Customer Service Projects			-	\$ 18,513	\$ 11,394	\$ 11,259
Facilities						
	Facilities Services	Program	-	4,022	6,694 *	4,534
	Shoreham Facility Upgrades	Program	-	884	2,250 *	-
Total Facilities Projects			-	\$ 4,906	\$ 8,944	\$ 4,534
Fleet						
	Fleet	Program	-	9,655	5,495	10,735
Total Fleet Projects			-	\$ 9,655	\$ 5,495	\$ 10,735
Grand Total PSEG Long Island Projects with Carryover					\$ 657,632	\$ 682,397
FEMA Related Projects					\$ 153,609	\$ 49,980
Storm Capitalization					\$ 3,501	\$ 4,243
PSEG Long Island and FEMA Related					\$ 814,742	\$ 736,620

* Includes carry over from 2018. See "Carry Over" table for details

(a) Project to date expenditures includes projects that began prior to 2018

**2018 Carry Over Costs into 2019
(Thousands of Dollars)**

	Location	Investment Description	2019 Carry Over Costs
Transmission & Distribution			
Regulatory Projects			
	East Garden City	EGC- Valley Stream (N-1-1)	3,153
Total Regulatory Projects			\$ 3,153
Load Growth Projects			
	Arverne	Underground 13kV feeder extension	200
	Culloden Point	Culloden Pt. 23kV Conversion to 33kV	1,384
	Hero	Hero Substation 9X 23kV to 13kV Conversion	24
	Bridgehampton	Bridgehampton (9R)-Buell (9E)-New 69kV Trans Ckt	2,700
	Southampton	Canal (9C)-Southampton (9B)-New 69kV Trans Ckt	7,152
	Flowerfield	Upgrade 69/13 kV substation & distribution feeder	80
	Kings Highway	Kings Hwy Install New Substation and Associated Distribution	7,468
	Massapequa	Massapequa Install New Substation	2,140
	Pilgrim	Replace 13kV switchgear & install new feeder	2,251
	Roslyn	Expand 138/13 kV substation and feeders	32
	Round Swamp	Establish new 69/13kV substation	730
	Ruland Road	Ruland Rd. to Plainview New 69KV Circuit	9,603
	Lake Success	Smart Wires - Lake Success to Stewart Manor to Whiteside	356
	Navy Road	Navy Rd. New 23-13 kV Sub & Assoc C&R	3,825
	Navy Road	Navy Road – 2nd 23-13kV Bank & Swgr and Trans / Dist Ckts	3,825
Total Load Growth Projects			\$ 41,770
Reliability Projects			
	Fire Island Pines	Install new 23 kV circuit to Ocean Beach	490
	Fire Island Pines	Install new 23 kV circuit to Davis Park	1,386
	Hicksville	Purchase two mobile units	170
Total Reliability Projects			2,046
Total Transmission & Distribution			\$ 46,969

**2018 Carry Over Costs into 2019
(Thousands of Dollars)**

	Location	Investment Description	2019 Carry Over Costs
Information Technology			
IT-Transmission & Distribution			
		New Business Requirements	200
		New Business Web Portal	150
		EMS upgrade LCP	250
		CGI CAD Upgrade	500
		LI DSCADA	250
Total IT-Transmission & Distribution			1,350
IT-Customer Service			
		CRM Modernization - Salesforce	600
		Customer 360 - New Analytics Platform	360
		Pinpoint Project to Eliminate SSN#s	100
Total IT-Customer Service			\$ 1,060
IT-Information Technology			
		LCP 2018 Prog - Laptops	750
		LCP 2018 Prog - Mobile Data Terminals (MDTs)	1,700
Total IT-Information Technology			\$ 2,450
Total Information Technology			\$ 4,860
Business Services			
Facilities			
	Hicksville	Operations 2 Renovation	2,041
	Shoreham	Shoreham Segmentation	2,250
Total Business Services			\$ 4,291
Total Project Carry Over			\$ 56,120

Long Island Power Authority
2019 Proposed and 2020 Projected Operating and Capital Budgets

LIPA's Relationship with New York State Government

The Long Island Power Authority is a component unit of New York State. The Authority became the retail supplier of electric service in the Counties of Nassau and Suffolk (with certain limited exceptions) and a portion of Queens County known as the Rockaways (Service Area), on May 28, 1998 by acquiring the transmission and distribution system of the Long Island Lighting Company as a wholly owned subsidiary of the Authority. The Authority provides electric delivery service in the Service Area, which includes approximately 1.1 million customers. The population of the Service Area is approximately 2.9 million. In order to assist the Authority in providing electric service to its customers, the Authority entered into operating agreements to provide the Authority with the operating personnel, and a significant portion of the power supply resources, necessary for the Authority to provide electric service.

Under the Authority's business model, essentially all costs of operating and maintaining the Authority's T&D system incurred by PSEG Long Island, the Authority's Service Provider, are passed through to and paid for by the Authority.

Long Island Power Authority 2019 Proposed and 2020 Projected Operating and Capital Budgets

Budget Process

Under the terms of the LIPA Reform Act and the Amended and Restated Operations Services Agreement, the LIPA Consolidated Budget and Financial Plan are jointly developed by LIPA and its Service Provider, PSEG Long Island.

The LIPA Consolidated Budget outlines projected spending by major expense and revenue category. The budget reflects the operating and capital costs required to provide electric service in the Service Area.

Budget Development Schedule:

- April through October: LIPA and PSEG Long Island develop projections of current year spending and preliminary budget forecasts for the upcoming year and financial plan.
- June through October: PSEG Long Island provides LIPA with preliminary Capital project projections.
- October:
 - PSEG Long Island provides LIPA with a preliminary budget. This includes projections for current year spending as well as a preliminary budget for the years covered by the financial plan. The preliminary budget submission is reviewed by LIPA.
 - LIPA provides PSEG Long Island its portion of the Consolidated Budget by mid-October.
 - PSEG Long Island produces a LIPA Consolidated Budget by the end of October.
 - The LIPA Consolidated Budget is reviewed by senior level staff from both LIPA and PSEG Long Island.
- November:
 - Public Hearings are held in November to solicit comments from the public.
 - The Board of Trustees is briefed on the budget during Budget Workshops.
- December: The Board of Trustees votes on the adoption of the LIPA Consolidated Budget.

Certification

I hereby certify that, to the best of my knowledge and belief after reasonable inquiry, the budget information and financial projections contained herein for the years ending December 31, 2018 through December 31, 2020 have been developed based on reasonable assumptions and methods of estimation and that the requirements of 2 NYCRR Part 203 have been satisfied.

/s/

Thomas Falcone
Chief Executive Officer
Long Island Power Authority

Dated: December 19, 2018

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**Department of
Public Service**

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John B. Rhodes
Chair and
Chief Executive Officer

Thomas Congdon
Deputy Chair and
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John J. Sipos
Acting General Counsel

Kathleen H. Burgess
Secretary

November 1, 2018

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

Re: Matter No. 14-01299: In the Matter of PSEG LI Utility 2.0 Long Range Plan;
Recommendations Regarding PSEG LI Annual 2018 Update

Dear Chairman Suozzi:

I am pleased to provide the recommendations of the New York State Department of Public Service (DPS or Department) regarding PSEG Long Island's (PSEG LI, the Company, or Service Provider) annual update to the Utility 2.0 Long Range Plan (the 2018 Plan). In its 2018 Plan, PSEG LI proposes nine major programs comprising Smart Meter Deployment, Rate Modernization, expansion of the Company's Super Saver PILOT Program, Utility Scale Storage, Behind the Meter Energy Storage, expansion of PSEG LI's Electric Vehicle (EV) program, upgrades to the Interconnection Online Application Portal (IOAP)¹, a Locational Value Study, and a Non-Wire Solution Planning program. The Department recommends that certain of the proposals be adopted with the Department's recommendations and that others be revised and re-submitted in future Utility 2.0 Long Range Plans. The total cost of PSEG LI's proposal, as reflected by the Department's recommendations, is approximately \$306.6 million through 2022.

Statutory Authority

Pursuant to Public Authorities Law (PAL) §1020-f(ee); the Long Island Power Authority (LIPA) and its service provider PSEG LI submit to DPS on an annual basis any proposed plan related to implementation of energy efficiency measures, distributed generation or advanced grid technology programs having the purpose of providing customers with tools to more efficiently and effectively manage their energy usage and utility bills, and improving system reliability and power quality. In accordance with Public Service Law §§3-b(3)(a) and (g), DPS reviews and makes recommendations to LIPA with respect to the plans and rates and charges, including those related to energy efficiency and renewable energy programs

¹ IOAP formerly referred to as Smart Grid Interconnection Portal or SGIP.

PSEG LI 2018 Utility 2.0 Annual Update Proposal

On June 29, 2018 PSEG LI submitted to DPS its 2018 Annual Update to the Utility 2.0 Long Range Plan. The total cost of PSEG LI's 2018 proposal is approximately \$321m over four years, 2019 through 2022. Reflecting projected savings of \$54m, the net cost is approximately \$265m over the four years.

PSEG LI proposes Capital expenditures over four years of approximately \$239.4m before benefits are taken into account and \$234.2m after benefits are taken into account. On an annual basis, PSEG LI proposes Capital expenditures of \$74.5m, \$52.1m, \$56.0m and \$56.9m for 2019, 2020, 2021 and 2022 respectively.

PSEG LI proposes Operations and Maintenance (O&M) expenditures over four years totaling approximately \$79.7m before benefits are taken into account and \$31.0m after benefits are taken into account. On an annual basis, PSEG LI proposes O&M expenditures of \$21.0, \$18.0, \$19.7, and \$20.9m in 2019, 2020, 2021 and 2022 respectively.

PSEG LI's proposal also includes Fuel & Purchased Power expenditures over four years totaling approximately \$0.5m. On an annual basis, PSEG LI proposes expenditures of \$43k, \$79.7k, \$180.5k, and \$241k for 2019, 2020, 2021 and 2022 respectively.

PSEG LI performed multiple Benefit Cost Analyses (BCA), where applicable, of its 2018 Utility 2.0 programs and projects. PSEG LI provided a summary of the program costs and the associated BCA ratios in its 2018 filing.² The BCA analyses performed by PSEG LI, and DPS review of those analyses, are consistent with the BCA process relating to Investor Owned Utilities (IOUs) pursuant to Commission Order.³ In July 2014, DPS provided recommendations in response to PSEG LI's first Utility 2.0 filing. In DPS' recommendations the Department stated that:

A primary objective in the DPS review of the Plan was that it include programs that will create consumer value in the near term by accelerating the achievement of REV objectives... as the Plan evolves through annual filings and the refinement of its programs, the type of market-based solutions to address system challenges consistent with and along the lines envisioned through REV, will become clearer and better understood.⁴

² Matter No. 14-01299, In the Matter of PSEG-LI Utility 2.0 Long Range Plan, PSEG LI Utility 2.0 2018 Annual Update, p. 6.

³ Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016) and Case 16-M-0412, Benefit-Cost Analysis Handbooks, Notice of New Case Number and Soliciting Comments on the Benefit-Cost Analysis Handbooks (issued July 27, 2016).

⁴ Matter 14-01299, DPS Recommendations of PSEG's First Annual Long Range Plan (issued April 15, 2014), p. 1.

The BCA analyses performed by PSEG LI, where applicable, demonstrate that the programs and projects proposed in this Update are expected to provide benefits outweighing the cost of ratepayers' investments in Utility 2.0.

Staff Review and Public Comments

The Department conducted an extensive review of the nine proposals submitted by PSEG LI. Staff from DPS, LIPA, and PSEG LI engaged in weekly technical conferences and DPS Staff issued numerous document and information requests in its evaluation of PSEG LI's 2018 Plan. Staff reviewed the substantive aspects of the programmatic proposals made by PSEG LI, the benefits and costs, cost recovery mechanisms, and the rate impacts of each proposal.

In the course of its review, on July 16, 2018, the Department issued a Notice Requesting Comments on PSEG LI's 2018 Annual Update. The Department received comments from numerous private citizens and organizations including the New York Power Authority (NYPA), Sierra Club, Natural Resources Defense Council, All Our Energy, Citizens Campaign for the Environment, Environmental Advocates of New York, Renewable Energy Long Island, Town of Southampton, Suffolk County Legislature, Chargepoint, SunPower with Empower Solar, Edgewise Energy, E Cubed LLC, Sunrun, Greenlots, NY BEST, and the Alliance for Clean Energy New York. All public comments are available on the Departments Document Matter Management website.⁵

The comments recognized many of the benefits of PSEG LI's proposals, and noted areas for enhancement, including for example the need for stakeholder involvement and ease of access to smart meter data. Comments expressed the need for PSEG LI to continue to engage communities in creating customer focused proposals, introducing more customer choice and the integration of customer and developer needs. The public comments also noted the importance of information sharing between PSEG LI and third parties; suggesting that PSEG LI include more detail regarding the tools used by the utility and how these tools can be shared to understand system needs and potential business opportunities. The Department considered the comments in development of its recommendations.

AMI Smart Meter Deployment

A major element of PSEG LI's 2018 Utility 2.0 proposal is the full-scale deployment of approximately 1 million AMI smart meters from 2019 through 2022. PSEG LI projects that the proposal will cost approximately \$230.3 million in capital expenses and \$49.7 million in O&M expenditures over the four-year deployment period. The Department recommends that PSEG LI proceed with the proposed full-scale deployment of AMI Smart Meters on Long Island. DPS recommends minor modifications to the project as recommended herein.

DPS recommended, following its review of PSEG LI's 2017 Update, that rather than full AMI deployment as PSEG LI had proposed, PSEG LI proceed with the installation of 15,000 smart meters as proposed for 2018, and postpone full AMI deployment pending resubmission of

⁵ Matter 14-01299, In the Matter of PSEG-LI Utility 2.0 Long Range Plan.

its plan with a more fully developed BCA in 2018.⁶ PSEG LI has continued to leverage its island-wide AMI communications network, and including the meters installed by the end of 2018, is expected to complete the installation of AMI for approximately 10% of the customer base (115,000 meters) measuring over 40% of system energy. PSEG LI continues to install smart meters focusing on large commercial customers with existing TOU rates, net metered customers, safety-related accounts, the Bellmore Super Savers saturation deployment, the Patchogue Super Savers saturation deployment, Life Support Equipment (LSE) customers, and accounts that would reduce long-term estimates. PSEG LI has also been pursuing, since 2017, upgrades to its Meter Data Management System (MDMS) to improve the Customer Portal, enhance system flexibility to support future hourly pricing rates, improve data security, improve the meter-to-cash process, and enhance its data Validation, Estimation and Editing (VEE) capabilities.

Among the benefits of smart meters is that they enable customers to make smarter energy decisions and will enable PSEG LI to offer new rate structures, increase capabilities to detect outages and restore service more quickly, allow for more timely outage communication with customers, enable remote connect/disconnect of meters, allow for a more tailored customer service, improve revenue protection solutions thereby reducing theft of service, and streamline internal processes to enhance customers experiences.

In the Department's review of the Smart Meter Deployment proposal, Staff reviewed the extent to which PSEG LI included a detailed implementation plan, processes for system integration, a comprehensive customer engagement plan, innovative pricing proposals, appropriate benchmarking, and a strong and evolving physical and data security plan. Staff also reviewed the extent to which input from third parties was taken into account and to which PSEG LI remains adaptable in the face of evolving technologies, customer needs, and energy policy. Staff also evaluated the effectiveness of performance metrics for PSEG LI's successful deployment of AMI smart meters. As proposed, PSEG LI's full-scale deployment links to other initiatives aimed at improving reliability of the transmission and distribution system and provides new innovative rates for customers. Each of these components supports PSEG LI's vision of a Utility of the Future (UoF) to inform the projects included in the 2018 Utility 2.0 filing and future annual update filings.

PSEG LI incorporates lessons learned from the implementation of AMI within LIPA's service territory since 2009, and PSEG LI's progress in developing the foundational components of its smart meter program. The robust benefits identified in the BCA submitted as part of the 2018 Update filing support PSEG LI's deployment goals. Full deployment of AMI meters should be completed within the proposed four-year period and within the projected capital and O&M costs. In accordance with its BCA, PSEG LI should demonstrate cost savings that exceed total cost. Identified cost savings should be incorporated in the determination of future updates and rates.

To encourage successful completion of the full-scale AMI deployment, the Department recommends that PSEG LI track deployment of AMI meters by township, and submit to the

⁶ Matter 14-01299, DPS 2017 Utility 2.0 Annual Update Recommendations (issued December 14, 2017), p. 4.

Department, on a quarterly basis starting April 30, 2019, schedules identifying the beginning and end dates for meter installation for each township prior to deployment in each town as they are developed. Where rate pilots or other programs are dependent on AMI smart meters for their implementation, the AMI smart meter deployment schedule should coordinate with those programs. DPS also recommends that PSEG LI identify any variations that may occur in the AMI meter deployment schedule and explain the reason for such variations. To the extent there are delays in the deployment of smart meters, PSEG LI should identify in the reports, corrective actions that have been or will be put in place to improve AMI meter deployment. PSEG LI should also separately identify to the Department the number of residential and commercial meters installed by township.

To track project costs and progress, DPS recommends that PSEG LI report annually starting July 1, 2020, the number of power quality issues identified through AMI smart meter deployment which resulted in elimination of the need to dispatch PSEG LI crews, avoided outage restoration costs for each outage event, avoided meter operations O&M costs identified by the type of saving (e.g., avoided outage cost or meter service), and reductions in call center and billing costs.

As part of PSEG LI's quarterly filing, PSEG LI should report to DPS on the status of PSEG LI's alignment with the recommendations in the National Institute of Standards and Technology (NIST) issued in September 2014.⁷ Until PSEG LI fully aligns with the recommendations, the Company, should include in its quarterly reports, the status of the seven (7) partial-alignments and one (1) non-alignment that PSEG LI identified in its filing.⁸ Staff also recommends that PSEG LI's quarterly report include the extent to which PSEG LI's policies align with the Fair Information Practice Principles (FIPP). PSEG LI should include in its quarterly reporting, how it implements FIPP and how it will continue to do so. FIPP creates additional layers of customer focused data protection. A number of the topic areas typically found in FIPP are already included in the Company's existing privacy policies, however, the Company should continue to enhance its existing policies.

DPS also recommends that PSEG LI include the status of the Company's outreach plan in its quarterly reports. The reporting should include the status of outreach to customers, stakeholders, and elected officials. The report should also list, the number of customers contacted, details of the Company's success in contacting customers, any questions and complaints from customers and stakeholders, and meetings with elected officials. In addition, Staff recommends that as deployment continues, the Company provide updates in its quarterly reports, on its outreach to Low Income customers. The updates should identify specifically targeted communities, the outreach strategy employed and an assessment of the success of these strategies.

PSEG LI identified in its filing⁹ its own robust data analytics program, however, DPS recommends that PSEG LI continue to develop its plans to share its utility-customer energy data with third parties. Currently, PSEG LI's process for data sharing with third-parties is a paper

⁷ NISTIR 7628 Rev. 1. https://ws680.nist.gov/publication/get_pdf.cfm?pub_id=917244

⁸ Matter No. 14-01299, PSEG LI Utility 2.0 2018 Annual Update, p. 53.

⁹ Matter No. 14-01299, PSEG LI Utility 2.0 2018 Annual Update, pp. 26-28.

process initiated by customers, providing interval data within five business days. In its 2018 Utility 2.0 proposal, to enable customers to access their energy data through the MDM Customer Portal, PSEG LI proposes that beginning in 2019, through the deployment of AMI smart meters, the new MDMS, Advanced Billing Engine, and Customer portal, customers will be able to create a registration link for a third-party to access and download energy data in CSV and Green button formats. Third-parties would be able to login via the registration link to download 12 months of interval customer data. PSEG LI states that this approach empowers the customer to define the validity of the access to their energy data to keep the data access secure. The Department stresses the importance of utility-customer energy data sharing and PSEG LI's obligation to provide necessary privacy protection.

DPS encourages PSEG LI to review Staff's New Efficiency New York white paper as it relates to data sharing.¹⁰ PSEG LI should consider Staff's comments in addressing the challenges of designing utility programs involving specific customer targeting, propensity modeling, and those seeking to inform decisions regarding the cost effectiveness of utility operations. The Company must also meet the challenge of implementing effective and comprehensive procedures for data and customer privacy. DPS recommends that PSEG LI and LIPA engage with the Joint Utilities in the PSC's Data and Cyber Security proceeding¹¹ and collaborate with the Joint Utilities and DPS Staff to address emerging issues in this topic area. PSEG LI's progress in implementing Green Button Connect may be informative to other NYS Utilities as they implement similar data sharing programs. PSEG LI should work with the other NYS Utilities to create data sharing programs with standardized, consistently applied provisions to alleviate divergence among utility practices. Potential divergence in utility practices may negatively impact customers and third-party market participants. As these discussions develop, PSEG LI should consider emerging issues related to customer opt-outs and the implications of sharing aggregated utility scale data. DPS also recommends that PSEG LI and LIPA engage NYSEERDA, within the first quarter of 2019, to initiate a process for uploading aggregated monthly data by municipality to NYSEERDA's Utility Energy Registry (UER), consistent with the PSC's April 20, 2018 Order.¹²

As discussed in New Efficiency New York,¹³ increased access to useful data and information, is an essential market enabling action. Specifically,

Market-enabling actions help create the environment for more efficient and engaged markets, provide market actors the ability to deliver more economic and compelling solutions to consumers, and facilitate the transition to more market-based mechanisms that can deliver efficiency at greater levels of scale.¹⁴

¹⁰ Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, New Efficiency New York (issued April 26, 2018), pp. 37-40.

¹¹ Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place.

¹² Case 17-M-0315, In the Matter of the Utility Energy Registry, Order Adopting Utility Energy Registry (issued April 20, 2018).

¹³ Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, New Efficiency New York (issued April 26, 2018).

¹⁴ Id., p. 37.

Utilities should not artificially restrict customers, stakeholders, and other market participants from creating a more efficient and engaged market. The Department stresses the importance of actively enabling “the development of energy efficiency market activity at scale including energy usage data, both at the individual customer and at the aggregated community level.”¹⁵ The Department reiterates that more robust access to and uses of data hold great promise to support significant growth in the energy efficiency market and achievement of the State’s energy policy objectives.¹⁶ PSEG LI’s 2019 Utility 2.0 proposal should emphasize a significant commitment to enable customer and authorized third-party access to customer data.

PSEG LI explained that the initiatives proposed in the 2018 Utility 2.0 filing are intended to further enable AMI capabilities, including development of what PSEG LI calls its “big data strategy”, which is expected to serve as a platform for enterprise data analysis and reporting.¹⁷ The big data strategy will be developed in future filings. DPS recommends that PSEG LI’s 2019 Utility 2.0 proposal include the status of these data sharing issues being addressed by PSEG LI and include proposals to more effectively utilize the AMI data in collaboration with stakeholders and other market participants.

PSEG LI indicated that additional levels of interactivity are planned as part of its post roll-out planning process and are a part of the UoF group’s charge as follows:

The Modernizing Stage is the future of PSEG Long Island and its customers. The utility will have become a fully AMI-enabled utility with digitally-enabled customers. Customers will engage with the utility through more information and control of their energy consumption; they should become a participant in the energy community using these new products and services. PSEG Long Island will continue to modernize the rates and services available to its customers while improving the reliability and operation of the electric grid using advanced analytics and operations capabilities. Ultimately, PSEG Long Island will be in a position to start enabling the DSP vision for New York State.¹⁸

PSEG LI states:

The mission of the UoF Team will be to take ownership for and proactively drive the development of REV-related capabilities and meet REV objectives as they evolve in the New York regulatory environment. This effort is consistent with the PSEG Long Island business strategy to continue to align with REV objectives and other New York State policy goals. The UoF Team will serve as one of PSEG Long Island’s core business functions. It will support and integrate closely with AMI analytics as well as spearhead the utility’s shift from system-level planning, capital investment, and tariff design to granular, more locational-based T&D planning, T&D capital investment, technical and market demonstrations, policy development, and innovative tariff design.¹⁹

¹⁵ Id.

¹⁶ Id.

¹⁷ Matter No. 14-01299, PSEG LI Utility 2.0 2018 Annual Update, p. 44.

¹⁸ Id., p. 46.

¹⁹ Id., p. 41.

DPS recommends that PSEG LI proceed with development of the UoF Group's Policy & Demonstration Projects which effectuate PSEG LI's commitment to REV initiatives including industry collaborations and PSEG LI's participation in various REV working groups such as supporting initiatives related to VDER. DPS recommends that PSEG LI and LIPA emphasize to the UoF group the importance of developing and implementing market-enabling action to increase the interactivity between the Utility, customers, stakeholders, and market participants. PSEG LI's future proposals should include implementation plans, budgets, and timelines necessary to further enable energy efficiency markets and spur private investment.

Another source of benefits that are presently unquantified lies in the opportunity for PSEG LI and LIPA to work with advanced energy companies and/or benefit from novel technology solutions to develop alternatives that achieve the same results of the Company's multiyear plan at lower ratepayer expense. These efforts could take the form of technology alternatives that are more optimal for specific locations or types of customers, or alternatives that can produce additional revenues from third-parties, to offset costs under the proposed budget. DPS recommends that PSEG LI and LIPA continue to work with third-parties to identify these opportunities and pursue them as warranted.

DPS also recommends that prior to or immediately after completing its integration of AMI data with the Company's Outage Management System (OMS) and other applications, PSEG LI conduct a stress test to simulate the data flow between the AMI system and all other applications that will receive AMI data. Specifically, the OMS should be stress tested to simulate simultaneous system-wide outages, multiple per customer calls and high data flow of SCADA and AMI data. The level of integration should be tested to ensure that the OMS can accommodate the extremely large amounts of data that AMI may provide. Any identified capacity, programming, or other problems should be corrected immediately.

DPS recommends that PSEG LI continue to pursue cost savings to reduce the average cost of its residential and commercial AMI smart meters. Staff compared PSEG LI's AMI meter cost with other NYS Utility AMI filings and found that PSEG LI's meter costs are slightly higher than average. PSEG LI's cost per AMI meter has remained the same since 2012, while the cost of meters has decreased over time. In consideration of the increased number of AMI meters PSEG LI plans to install over the upcoming four-year period, PSEG LI should pursue volumetric savings to the extent possible. Cost savings should be incorporated into the calculation used to determine future update filings and future rates.

Although PSEG LI's per meter cost is slightly higher than other NYS Utilities, the projected benefits PSEG LI expects to obtain in the longer term exceed the costs of the proposal. PSEG LI identifies a large amount of savings in avoided O&M costs comprised of labor transition, vehicle, meter service, billing and call center representative cost savings. Other major drivers of projected benefits include avoided outage costs and reductions in restoration costs, revenue protection, theft and tamper protection, and benefits associated with PSEG LI's Time of Use (TOU) rate offerings.

Based on DPS Staff's review of the Smart Meter Full Deployment Plan proposed in the 2018 Utility 2.0 Plan, the associated BCA performed by PSEG LI and Navigant, and PSEG LI's

Customer Outreach Plan, the Department recommends that PSEG LI proceed with full-scale deployment of AMI Smart Meters on Long Island as proposed. DPS also recommends minor modifications to the project and reporting consistent with the recommendations stated above.

Rate Modernization

PSEG LI states in the 2018 Utility 2.0 filing, the “AMI Smart Meter program enables the functionality required to modernize PSEG Long Island’s rates and provide customers with a wide variety of options and tools to control electric usage and make cost-effective choices with increased convenience.”²⁰ PSEG LI’s Rate Modernization program seeks to further align PSEG LI’s operations with New York State REV goals, offer customers rate options that are simple to understand, easy to compare, and meet current and future utility needs. PSEG LI requests \$9.5 million for an Advanced Billing Engine in 2019, \$10.1 million in O&M expenses through 2022 for customer engagement and marketing, and \$7.8 million in O&M expenses for development and integration of the Advanced Billing Engine. DPS recommends that PSEG LI pursue the Advanced Billing Engine and associated outreach and marketing campaign, however, the Department recommends that PSEG LI submit to the Department any future rate design proposals for its review as part of the tariff amendment process consistent the recommendations contained herein.

The Rate Modernization proposal seeks funding for an Advanced Billing Engine and associated customer outreach and marketing. PSEG LI’s proposed Advanced Billing Engine includes a rate calculator, enhanced modelling and reporting capabilities, and enables PSEG LI to generate more advanced customer facing reports. As PSEG LI discusses in the filing, the Advanced Billing Engine is required to conduct rate PILOTS, customer research and system planning. The Advanced Billing Engine is a key component in PSEG LI’s efforts to pursue its enhanced analysis, training, change management, stakeholder engagement, customer acquisition and billing, process improvement, and customer service quality assurance. The Advanced Billing Engine is necessary to design and implement flexible, robust information systems that support diverse rate creation, rate calculations, customer engagement and communication tools to engage customers in adoption of new rates, in order to achieve maximum benefits, load reduction and customer satisfaction. The Department accordingly recommends that PSEG LI pursue the Advanced Billing Engine and the associated outreach efforts.

The Rate Modernization program PSEG LI proposes includes several different rates, riders, and/or general rate strategies. These include: Modified Residential and Small Business Short Peak TOU rates, Modified Medium and Large Business Short Peak TOU rates, Residential and Small Commercial Three Time Block TOU rates, Residential Electric Vehicle (EV) TOU rates, Value of Distributed Energy Resources (VDER), Green Rider rate and a Good Neighbor rate. The Modified Residential and Small Business Short Peak TOU rates (also known as Power to Save) are current tariff offerings effective August 1, 2018, for which DPS recommended approval. PSEG LI proposes to modify current rates (M188 and M288) to shorten the peak period from its current seven hour period to five hours, from 2:00 p.m. to 7:00 p.m. on weekdays. The rate differential is designed to produce a 3 to 1 peak to off-peak price ratio during the summer and a 1.5 to 1 peak to off-peak ratio during the winter. Shortening the peak

²⁰ Id., p. 30.

period to 5 hours is consistent with best practices throughout the United States, and will enable customers to shift their consumption to generate savings.

As future rate modernization initiatives, PSEG LI generally proposes development of a Residential and Small Business Three Block TOU rate, and a Residential Electric Vehicle rate, which is planned for 2019 - 2020, followed by a pilot and assessment period, with full deployment scheduled beginning in 2022. Other rates PSEG LI proposes to develop in the future include Medium and Large Business Rates to be launched in 2020, Green Rates, a Good Neighbor Rate, Mandatory Hourly Pricing, Critical Peak Pricing, and Residential Demand Automation (Smart Home Rate).

While the rates PSEG LI is considering are generally consistent with REV goals as described in the 2018 Utility 2.0 filing, the specifics of each rate proposal, including the rate design assumptions and workpapers, should be provided to the Department for its review through the tariff modification process or future Utility 2.0 proposals.

DPS generally supports the Residential Three Time Block TOU Rate, with suggested modifications set forth below. Other NYS Utilities offer at least a two-period TOU rate, and may move to three-period TOU rates which is more innovative than two block rates and more in keeping with REV objectives. On most utility systems, there are a limited number of hours during which the system is at very high peak and load. A three-period TOU rate offers more granular pricing that more accurately reflect the costs of these system conditions. It is expected that PSEG LI will consider periods which best reflect its system conditions. For example, proposals which create super-off-peak periods on weekends and holidays may be appealing to customers. Furthermore, a larger price differential between the super off-peak, off-peak, and peak periods would allow for lower super off-peak rates to empower customers in certain instances, such as in EV charging.²¹

The Department also recommends that PSEG LI consider the extent to which the objectives of the Residential Electric Vehicle TOU Rate are more effectively achieved as part of the Residential Three Time Block TOU Rate. PSEG LI states that the rate, as described in the 2018 Utility 2.0 filing, allows EV owners to reduce their electric bills by charging their EVs during the super off-peak overnight period without having to compete with their households' energy usage during afternoon peak periods. Electric Vehicle owners as early adopters are more likely to be engaged, willing and able to manage their energy usage, and accordingly, the Residential Three Time Block TOU Rate through its the super off-peak period would optimize EV charging.

In accordance with the foregoing discussion, DPS recommends that PSEG LI pursue the Advanced Billing Engine and associated outreach and marketing campaign. The Department recommends that PSEG LI submit to the Department for review any future rate design proposals through the tariff amendment process consistent the recommendations contained herein.

²¹ See, Case 18-E-0206, Residential Electric Vehicle Charging Tariff Filings, Filings suggested rate guarantees for EV owners.

Super Savers

PSEG LI in its 2018 Utility 2.0 Update filing proposes expanding its Super Savers Program demonstration project to the Patchogue area. PSEG LI requests \$1.65 million of O&M for 2019 and 2020 for this project. Attendant capital spending is included in the AMI Smart Meter proposal. Additionally, PSEG LI proposes a Voltage/VAR Optimization (VVO) Study as part of the Super Savers Program in North Bellmore and Patchogue and a Standard Offer Program to incent load reduction programs. The Department recommends that PSEG LI pursue the expansion of the Super Saver Program in the Patchogue area and the VVO Study, however, the Department does not recommend that PSEG LI pursue the Standard Offer Program component.

PSEG LI's proposal to expand the Super Savers Program to Patchogue applies the same array of programs included in the North Bellmore's Super Savers program for which the Department recommended approval in 2017.²² PSEG LI identified 4 MW of targeted peak demand reduction to be achieved in North Bellmore when the Super Saver program is fully implemented, thereby, creating approximately \$2.3 million in net savings by deferring associated capital projects for at least 5 years. The Super Savers program in Patchogue is targeted to achieve 2 MW of peak demand reduction, creating a potential net savings of \$1.86 million and an associated 3-year capital project deferral. PSEG LI states that the benefits of the Super Saver program include avoided generation capacity cost, avoided energy, net avoided CO₂, and most importantly avoided distribution capacity costs.²³

Generally, the Super Saver program proposal accords with DPS 2017 recommendations,²⁴ and the program is a key component in achieving the Department's policy to defer traditional T&D capital project investment by utilizing non-wire alternative (NWA) solutions.²⁵ Further to the Department's Utility 2.0 recommendation in 2017, the Department continues to support PSEG LI's pursuit of the Super Saver program in this year's Utility 2.0 recommendation. DPS recommends that PSEG LI submit to the Department, on a quarterly basis beginning April 30, 2019, a progress report on the status the Super Saver Program in North Bellmore and Patchogue.²⁶ DPS also recommends that PSEG LI include the number of customers participating for each component program, (i.e., Home Energy Audits (HEA)/ Home Energy Review (HER), Smart Devices, and Direct Load Management (DLM)), the projected and actual kW/kWh load reduction achieved for each program, and an overview of the program's status. As part of future Utility 2.0 proposals, DPS encourages PSEG LI to consider expanding its Super Savers program to benefit other communities if results demonstrate that the targeted savings in North Bellmore Patchogue are achievable. PSEG LI should continue to evaluate the feasibility of gaining additional economic, environmental, and social benefits through further expansion of the program, as suggested in the public comments.

²² Matter No. 14-01299, Recommendations Regarding PSEG LI Annual Update, p.8

²³ Matter No. 14-01299, PSEG LI Utility 2.0 2018 Annual Update, p. 85.

²⁴ Matter No. 14-01299, Recommendations Regarding PSEG LI Annual Update, p.8

²⁵ Case 14-M-0101, Reforming the Energy Vision.

²⁶ See, Appendix 2 of for the Utility 2.0 Plan 2017 Annual Update, p. 22.

The VVO study PSEG LI proposes is intended to improve voltage, loading, losses, and protection performances in both geographic areas. The Company's proposed VVO Study is a circuit-by-circuit study of voltage, transformer loading, phase balance, and fuse sizing. The results will inform PSEG LI in achieving an improved voltage profile, reducing customer consumption and improving phase balancing for loss reduction. Transformer Load Monitoring (TLM) of pole top transformers may reduce outages and thereby increase equipment lifetime. The program leverages additional benefits of the full deployment of AMI smart meters and provides essential information for outage reduction and conservation benefits. DPS supports moving forward with the program.

The Standard Offer Program for capacity saving PSEG LI proposes, of which DPS is not recommending approval for the reasons set forth below, is an annual incentive payment per kW of load reduction (\$/kW/year). The Standard Offer payment would apply to qualified capacity savings in the North Bellmore load pocket beginning in 2019. As proposed, the payment would apply to coincident peak demand savings of \$700/kW for the first-year, premised on verified peak demand savings occurring in 2019 and 2020. The Standard Offer would be available to any eligible market participant that registers with PSEG LI and delivers targeted capacity savings.

DPS believes that a minimum guaranteed demand savings, annually or over the total length of time PSEG LI engages with providers, should be established and verified for effective implementation of the Standard Offer program, and should be included if PSEG LI proposes this program in future update filings. PSEG LI should consider how to measure and verify the demand savings and introduce appropriate recoupment of unrealized demand reduction through measures which may include contract enforcement. Ensuring that the program provides demand savings is essential. As currently proposed, the lump sum incentive payment does not ensure long-term verifiable demand savings. PSEG LI should also consider the extent to which annualized payments may be appropriate. DPS accordingly recommends rejecting \$500K proposed in the O&M budget for Standard Offer Program for 2019 and 2020 and suggests PSEG LI resubmit the Standard Offer Program in future filings with more detail in particular with regard to ensuring the performance of long-term capacity savings. PSEG LI should also consider coordinating this program with similar NYS programs as they develop.

In accordance with the discussion above, the Department recommends that PSEG LI pursue the expansion of the Super Saver Program in the Patchogue area and the VVO Study, however, the Department does not recommend that PSEG LI pursue the Standard Offer Program component at this time.

Utility Scale Storage

PSEG LI proposes using energy storage technology deployed at the substation level to defer or replace conventional grid assets needed to support load growth and reliability needs. PSEG LI proposes to install a 2.5MW battery storage project at the Miller Place substation. PSEG LI's proposal includes total Capital cost of approximately \$4.9 million and a total O&M cost of approximately \$1 million through 2022. The Department recommends that PSEG LI pursue installation of the battery at Miller Place, and additional projects as set forth below, and consider in future Utility 2.0 filings the extent to which PSEG LI and LIPA can facilitate

increased storage through additional projects, commensurate with levels necessary to achieve New York State's 2025 storage goal.

Energy Storage is a versatile resource in the current electric grid and the electric grid of the future. Storage potentially defers traditional T&D projects, expands local capacity, increases grid efficiency by providing additional peak capacity without adding additional generation resources, and is essential to the effective development of intermittent renewable resources such as wind and solar. New York State's renewable energy goal of achieving 50% of the State's electricity through renewable generation resources by 2030 is in concert with the State's energy storage target of implementing 1,500 MW of storage by 2025. PSEG LI and LIPA have to date provided 10 MW of Battery storage across the service territory; consisting of 5 MW in Montauk and 5 MW in East Hampton.

PSEG LI's proposed Miller Place storage project is expected to defer transformer bank upgrades at the substation which will otherwise be necessary to accommodate additional capacity that will be required by summer 2023. This proposal provides a deferral of traditional T&D infrastructure with assets that support renewable resources creating a more dynamic and resilient grid that ultimately takes a step toward meeting Statewide Storage goals and DPS recommends that PSEG LI pursue the project.

PSEG LI identified and analyzed two additional Grid Storage projects, the Brightwaters and South Manor energy storage projects, for inclusion in this year's Utility 2.0 Update filing. PSEG LI does not currently propose to pursue these projects based on the identified economics for each. PSEG LI states that an energy storage solution at the Brightwaters substation would defer distribution bank upgrades. Energy storage installed at the South Manor substation would defer transmission line re-conductoring. Although PSEG LI considers the current economics associated with these two additional projects not to be conducive to PSEG LI's pursuit of those energy storage projects at this time, DPS recommends that PSEG LI pursue additional funding sources, and initiate planning and solicitation of energy storage projects at both the Brightwaters and South Manor substations, when additional funding from other sources is secured which would make the economics of these projects favorable. Although energy storage solutions continue to evolve, these projects constitute an opportunity to bring Long Island closer to its storage goals in accordance with State policy. PSEG LI should confer with DPS and NYSERDA to develop and solicit proposals for these projects. In addition, PSEG LI and LIPA should continue to consider and propose in future Utility 2.0 filings, alternative energy storage solutions.

DPS also recommends that LIPA amend its Resource Planning, Energy Efficiency, and Renewable Energy Operating Policy²⁷ during LIPA's annual policy review in July 2019. The policy should be amended to further align LIPA with the State's goal of implementing 1,500 MW of storage by 2025. Enhancing the policy will further demonstrate LIPA's commitment to implementing energy storage solutions. The policy should empower LIPA and PSEG LI to develop an appropriate energy storage resources goal. The policy should also consider how to reasonably address potential financial impacts to ratepayers. Specific projects that result from the policy and should be included in future Utility 2.0 filings.

²⁷ <https://www.lipower.org/wp-content/uploads/2018/08/1421-Resource-Planning-Energy-Efficiency-and-Renewable-Energy.pdf>

In 2017, LIPA issued its Draft Staff Recommendations concerning the Integrated Resource Plan and Repowering Studies.²⁸ LIPA stated in its recommendations that PSEG LI, “study the peaking generation fleet and its ability to accommodate the flexible operating profile required by greater amounts of renewable generation.”²⁹ As part of this on-going study, DPS recommends that PSEG LI and LIPA continue to evaluate how to appropriately pair energy storage with LIPA’s generation resources, specifically, those needed to address peak load conditions. Pairing energy storage solutions with these resources has numerous benefits. Energy storage bolsters reliability, improves resiliency, allows these resources to run less often reducing emissions, and in the case of exceptional demand conditions stored energy can be discharged as a component of demand response.

DPS recommends that in the next Utility 2.0 filing, PSEG LI and LIPA report on their consideration of pairing energy storage solutions with peak generation resources at specific peaking units to meet evolving New York State energy and environmental goals and regulations. For example, energy storage may reduce the environmental impact of aging generation resources in furtherance of the Department of Environmental Conservation’s proposed NO_x regulations³⁰ and a study may be performed in conjunction with that process. PSEG LI should also continue to consider the potential impact of T&D infrastructure deferral or avoidance by pairing energy storage with existing peak generation resources and at the receiving sites for offshore wind as well as new system needs that begin to arise such as ramping resources to firm solar energy which energy storage could provide. To the extent a study can be expanded, it should also evaluate various scenarios that reflect increasing the MWs of storage installed on the system and analyzing storage goals exceeding 300MW.

In accordance with the foregoing, the Department recommends that PSEG LI pursue installation of the battery at Miller Place, and continue the Company’s efforts to evaluate the peaking generation fleet’s ability to include greater amounts of renewable resources including energy storage solutions. The Department recommends, that the additional projects in load constrained areas considered for inclusion in this year’s Utility 2.0 proposal be acted upon, if additional funding from other sources is secured.

Behind the Meter (BTM) Storage

PSEG LI is proposing to implement a 10-year tariff based incentive program through its Dynamic Load Management (DLM) tariff, specifically for residential and small commercial customers who have paired solar installations with energy storage solutions in load-constrained areas on Long Island. PSEG LI is requesting approximately \$600,000 in O&M costs to support this program through 2022. PSEG LI proposes to provide 7.6MW of BTM energy storage by 2022. The Department recommends that PSEG LI pursue the BTM Storage project and expand the project outside of load constrained areas on Long Island to be available systemwide, to all classes of ratepayers, and include both paired Photovoltaic (PV) and energy storage projects as

²⁸ Matter No. 17-00969, In the Matter of Long Island Power Authority and PSEG Long Island LLC Integrated Resource Plan, LIPA IRP - Draft Recommendation (issued April 24, 2017).

²⁹ Id., at 2.

³⁰ https://www.dec.ny.gov/docs/air_pdf/scctdraft.pdf

well as standalone energy storage projects designed to reduce customer load during utility demand response events. LIPA and PSEG LI should work with DPS Staff in the implementation of this recommendation.

PSEG LI proposes to initiate an open solicitation of third party aggregators, to install energy storage solutions paired with solar, while also providing load relief through direct load control. PSEG LI's proposal would offer a payment to third party aggregators who pair energy storage solutions with solar generation with direct load control capabilities to reduce load during called events. As proposed, PSEG LI would pursue 10-year agreements with third party aggregators, and thereby customers, that authorize terms and conditions of participation in the program. Through this program PSEG LI is offering a financial incentive of \$60/kW each year for load reduction during peak events. The incentive will be paid through an aggregator with a consistent level of savings being passed on to customers. Customers may benefit from both the financial incentive agreement with their aggregator and the added reliability offered during outage events by having onsite energy storage. PSEG LI's program also proposes to solicit a critical mass of participants in load constrained areas to defer future T&D capital upgrades. As the market grows in coming years, BTM storage will play a key role in meeting the statewide goal of 1,500MW in storage by 2025.

DPS supports this program as it defers capital investments in T&D, advances the growth of the storage market on Long Island, and supports the overall growth of energy storage to meet statewide goals. The program provides multiple benefits aligned with State policies. One of the primary objectives of REV is to stimulate new market segments to fulfill electric system requirements. BTM storage is a relatively new market. While residential and commercial installations for solar energy have increased significantly on Long Island, adoption of storage is not as prolific. Until recently, LIPA's tariff has not provided for storage assets to be interconnected into the electric system without pairing the storage with an eligible Distributed Energy Resource (DER) system such as solar. LIPA and PSEG LI should continue to consider expansion of the BTM program and this should be reflected in future Utility 2.0 filings.

DPS supports using this program as a starting point to stimulate and test the market for BTM storage applications. One advantage to offering this program now is that participants can take advantage of the Federal tax credits available through 2021 for paired PV and storage projects. These tax credits help offset the cost of the investment by the consumer and lower the overall cost of the program. While the program was initially proposed to be offered in load constrained areas only, the need for energy storage and its future applications on a system wide scale require it to begin as soon as possible. The Department also agrees with PSEG LI regarding the importance of the program being device and supplier agnostic to enable full market participation.

As proposed, there is no minimum level of kW's to which aggregators would be required to commit. DPS recommends that PSEG LI clarify, in its open solicitation or sooner, the minimum kW's aggregators or host site would be contractually obligated to provide. PSEG LI should continue to evaluate and expand upon this program in future Utility 2.0 filings, specifically considering the maximum number of customers to which PSEG LI can offer this program. BTM storage should be viewed as a system wide asset with the appropriate incentives

offered to customers who can supply the benefits it offers. DPS recognizes that additional studies, including PSEG LI's proposed Locational Value Study included in the 2018 Utility 2.0 proposal, are essential to the evolution of this program and the findings of those studies are expected to inform future filings. The Department also notes the importance of Statewide proceedings such as VDER that will impact the proliferation of BTM storage on a system wide basis. PSEG LI and LIPA should consider, in conjunction with other future Utility 2.0 programs, how storage may potentially play a role in offsetting load spikes, for example, similar to those associated with DC fast charging equipment for electric vehicles. PSEG LI should investigate this application and consider education initiatives regarding the benefits of pairing these two technologies.

Additionally, in future Utility 2.0 filings, PSEG LI should consider opportunities for direct enrollment by customers. Allowing customers to directly enroll will engage a larger customer base, further animate the market, and assist in spurring similar programs. The recent modifications to LIPA's tariffs, that enable BTM storage to be interconnected to the grid, are a significant step in enabling this technology, however, limitations requiring storage to be paired with another DER should be re-evaluated as these types of programs evolve.

In accordance with the foregoing, the Department recommends that PSEG LI pursue the BTM Storage project with the additional recommendation that it be expanded outside of load constrained areas on Long Island to enable a systemwide offering with higher value in load constrained areas and include standalone energy storage projects.

Electric Vehicles

PSEG LI proposes to expand its EV program to extend the commercial workplace charging program, offer a new residential smart charging program, introduce additional EV charger rebates, and provide financial incentives for public Direct Current Fast Charging (DCFC) port operators. PSEG LI projects the total cost of the proposal for EVs to be approximately \$20 million in O&M costs through 2022.³¹ The Department recommends that PSEG LI pursue the new residential smart charging program with modification, and the additional residential EV charger rebates. The Department recommends that PSEG LI not pursue the extension of its commercial workplace charging program, nor the incentives for DCFC operators. Instead, DPS recommends coordination with NYSDERDA with respect to its commercial workplace charging program and developing a revised proposal for DCFC incentives in collaboration with other NYS Utilities as part of the State's EV Generic Proceeding.³²

Concerning the Commercial Workplace Charging Program, in the 2017 Utility 2.0 recommendations, the Department recommended that PSEG LI offer incentives to install 100 EV charging ports through 2019.³³ PSEG LI targeted approximately 50 chargers for installation in

³¹ PSEG LI indicated to the Department the Capital Costs were erroneously reported in the 2018 update filing.

³² Case Number 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure.

³³ Matter No. 14-01299, Recommendations Regarding PSEG LI Annual Update, p.10.

2018 and installation of another 50 chargers in 2019. PSEG LI's incentive program offered commercial customers a rebate of the lesser of either 80% of the cost of the invoiced value of the EV charging equipment, or \$4,000 per port, up to 10 ports per customer, for a three-year term. PSEG LI proposes to extend the program and its offerings to an additional 1,700 ports through 2022. In September 2018, NYSERDA announced statewide incentives to offset the upfront costs for commercial workplace and other commercially sited installations.³⁴ This incentive will be available statewide, including on Long Island. Given the availability of this new incentive which should be set at a point to motivate customer acquisition of charging stations, DPS recommends that PSEG LI should not pursue the proposed commercial workplace charging station incentive, and instead coordinate with NYSERDA to increase the visibility of the already available incentives. To the extent PSEG LI considers future incentives, additional coordination with DPS and NYSERDA is encouraged to appropriately coordinate the incentives with others already available.

PSEG LI proposes to launch a new Residential Smart Charging Program in 2019. PSEG LI's proposal includes a program for residential EV charger rebates, and a behavioral incentive for off-peak charging. The residential EV charger rebate program encourages the installation of approximately 12,000 residential ports by 2022. The rebate provides for 80% of the cost of the invoiced value of the EV charging equipment, not to exceed \$500 per port, taken from a list of UL approved Level 2 residential chargers. In 2013, NYS announced a goal of 800,000 plug-in electric vehicles (PEVs) on the road by 2025 statewide. Charging infrastructure is critical to achieving this goal. Long Island plays a significant role in statewide EV expansion as the region currently accounts for almost one-third of the EVs deployed in the State. Widespread adoption of plug-in electric vehicles can provide a variety of economic benefits, including reduced overall electricity costs, savings in operating costs for EV drivers, and avoided costs through reductions in CO₂ emissions, as well as increased electric sales by the utility. In addition, many of the public comments the Department received express support for further investment in EV infrastructure. PSEG LI's proposal to incent the installation of residential charging ports is key component of meeting the State's goals. DPS recommends that PSEG LI pursue this program and that PSEG LI continue to encourage EV adoption across Long Island.

As part of the Residential Smart Charging Program, PSEG LI also proposes a behavioral incentive of \$.02/kwh to encourage off-peak charging. The incentive PSEG LI proposes may be insufficient to motivate changes in customer behavior. The proposal assumes the average electric vehicle uses 3,650kwh/yr, amounting to a total incentive amount of approximately \$73/yr or \$6/mo. Con Edison offers a similar incentive in its SmartCharge program. Comparatively, Con Edison's program offers a more robust incentive, which amounts to approximately \$365/yr or \$30/mo. Con Edison's methodology calculates the difference between the current delivery rate of the standard residential rate during summer months and the current off-peak time of use rate. Applying a similar methodology to the incentive PSEG LI proposes results in an incentive of between \$0.02-\$0.04/kwh. DPS recommends that PSEG LI increase the incentive to provide a more significant incentive for customers, at or above the higher range provided by applying this methodology. Increasing the incentive should bring the incentive

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<https://www.nyserda.ny.gov/All%20Programs/Programs/ChargeNY/Charge%20Electric/Charging%20Station%20Programs/Charge%20Ready%20NY>

more into line with the level being provided by Con Edison, whose service area is adjacent to that of LIPA.

PSEG LI also proposes to offer financial incentives for public DCFC port operators. To address high demand charges incurred by site hosts due to DCFC equipment while overall usage is still low, PSEG LI proposes a “set point” concept that attempts to set the cost to the driver to an equivalent price for gasoline. The utility would provide the difference in cost to the site host equating to a \$.40/kWh setpoint to port operators to achieve this goal. PSEG LI’s proposal to address high demand charges associated with DCFC, is worthy of exploration. DPS recommends that PSEG LI and LIPA not pursue implementation of this proposal in 2019 and that this proposal be considered within the context of the broader statewide initiative.³⁵ DPS commends LIPA and PSEG LI for engaging with other utilities in the PSC’s EV proceeding and their consideration of adoption of the associated PSC Order(s).³⁶ This important issue is not unique to Long Island, moreover, utilities should be aligned in their offerings to customers and market participants as EV adoption increases, and the increasing travel range of EVs allows customers to move more freely throughout various utility service territories. In addition, as mentioned previously, programs to encourage installation of DCFC should be considered in coordination with efforts to advance the use of energy storage technologies.

PSEG LI also proposes to conduct outreach regarding its EV programs. DPS recommends that PSEG LI increase the visibility of EV offerings through the Company’s “Save Energy & Money” section of its website. To the extent possible, PSEG LI should consider for future filings related to EV, coordination that is necessary to provide customers access through PSEG LI to EV offerings available in the marketplace. PSEG LI should also consider increasing the visibility of available rebates including reference to other programs, such as NYSEERDA’s or other Federal tax rebates and incentives. DPS encourages PSEG LI to consider offering “Ride and Drive” events like those supported by NYSEERDA. As PSEG LI develops its EV offerings, PSEG LI should consider how to incorporate ride-sharing programs, and outreach regarding EVs to multi-family housing, and low-income areas in future filings. Public comments also acknowledged a need for the electrification of large and/or commercial vehicles such as trucks and buses, and PSEG LI should consider the extent to which its EV programs can include these types of vehicles.

In accordance with the foregoing, DPS recommends that PSEG LI pursue the new residential smart charging program with modification, and the additional residential EV charger rebates. The Department does not recommend that PSEG LI pursue the extension of its commercial workplace charging program and the incentives for DCFC operators. DPS encourages PSEG LI to instead develop a revised proposal in collaboration with other NYS Utilities as part of the State’s EV Generic Proceeding.

Interconnection Online Application Portal (IOAP)

³⁵ Case Number 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure.

³⁶ LIPA filed notice, in August 2018 in the State Register, of its intention to participate in the proceeding and consider the Order(s) issued by the PSC in that proceeding for adoption by the LIPA Board of Trustees.

PSEG LI proposes as part of its 2018 Utility 2.0 update to enhance the Phase 1 implementation of its Interconnection Online Application Portal (IOAP)³⁷, which PSEG LI completed in January 2017. These enhancements will form the foundation for Phase 2. The enhancement work is anticipated to be completed in 2019. The Company is requesting a total of approximately \$4.5 million for the project. The funding includes Capital costs of approximately \$2.3 million and O&M costs of approximately \$2.2 million through 2022. After 2019, PSEG LI is requesting on-going subscription and support costs of approximately \$340k/year for three years. The Department recommends that PSEG LI pursue its proposed enhancements to the IOAP as recommended herein.

As discussed in the Department's 2017 Utility 2.0 recommendations, PSEG LI proposed SGIP implementation in three phases, however, the Company's proposal and phased objectives were not fully aligned with the recommendations of the Commission's Order Adopting Regulatory Framework and Implementation Plan ("Track One Order") or the Electric Power Research Institute (EPRI) report.^{38 39} Additionally, the proposed costs were considerably higher than those of other NYS utilities. The Department recommended that PSEG LI update its proposal in 2018 to be more consistent with the phased approach recommended by the REV Order and the EPRI report.

Both the Track One Order and the EPRI report tasked utilities with streamlining their interconnection application processes for distributed generation (DG) projects, increasing the transparency of their interconnection approval process, and adequately preparing for greater amounts of DG deployment expected in accordance with New York State's energy policy goals. The EPRI report specified the functional requirements of the IOAP and defined the implementation of each of the three phases outlined in the Tack One Order, thereby, providing directions for utilities to effectively implement the IOAP in NY.

PSEG LI's proposed enhancements to the IOAP will allow customers to quickly and easily submit interconnection applications, while also providing process management solutions and an application processing database. The proposed enhancements align PSEG LI with the rest of the state and will allow customers without a PSEG LI account number to apply online for interconnection. This feature allows PSEG LI to accept applications for non-inverter based technologies. PSEG LI's proposal to complete Phase 1 requirements will also provide a foundation for upcoming Phase 2 improvements in advance of automating technical review of applications.

In its next quarterly filing, upon availability of the necessary information, PSEG LI should report to the Department the status of its Phase 1 enhancements, as well as, an update on the planning and costs regarding RFPs for Phase 2 and 3 implementation. PSEG LI should

³⁷ Referred to previously as Smart Grid Interconnection Portal (SGIP).

³⁸ Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), pp. 88-89.

³⁹ EPRI, New York Interconnection Online Application Portal Functional Requirements, September 2016 ("IOAP Report").
[http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/\\$FILE/EPRI%20Task%201%20Memo%20Report_Final%209-9-16.pdf](http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/EPRI%20Task%201%20Memo%20Report_Final%209-9-16.pdf)

consult with Department Staff in development of its Phase 2 and 3 implementation plans, prior to implementation. Cost increases for maintenance and support of the IOAP beyond 2022 and 2023 should be controlled to the degree possible.

As stated above, the Department recommends that PSEG LI pursue its proposed enhancements to the IOAP, provide updates, and consult with Staff as recommended.

Locational Value Study

PSEG LI proposes to conduct a study to develop locational granular pricing to reflect the value DER additions will have on PSEG LI's distribution system. PSEG LI proposes to begin the study in early 2019, with the intention of completing the study by December 2019. For the locational value study, PSEG LI projects a Capital cost of \$1.0 million in 2019 and an O&M cost of \$2.1 million through 2022. The Department recommends that PSEG LI pursue the locational value study with modifications.

The locational value study proposed by PSEG LI is intended to develop a locational focus on costs and benefits and the tools and processes needed to evaluate potential NWS to offset and defer necessary T&D system upgrades. The study is a key component in considering specific temporal and locational details of potential NWS. PSEG LI states that the analysis would leverage a three to five-year horizon, and include active participation with the Joint Utilities Group, analysis of current Capital Plan drivers, forecast DER with a granular bottom-up methodology, develop Locational Values maps, and create a routine analysis methodology.

Current locational value analyses are not precisely aligned with the performance characteristics of DERs nor do they incentivize overcoming circuit-level or zone-level challenges. The locational value study should examine load information and associated T&D system limitations on a granular level to develop more precise information needed to incentivize DER solutions and for the evaluation of potential NWS projects. The locational value study will also develop zone-specific LSRV pricing that aligns compensation with the actual system benefit of DER solutions with the goal of sending market signals to third-party service and technology providers so that they target specific zones that benefit most from NWS.

In 2014, the PSC directed NYS utilities to design programs that reflect the marginal costs of avoided T&D investments, granular to the network or substation level if possible, as well as granular load information at the same network and substation level.⁴⁰ In 2016, as part of the REV proceeding, the PSC noted that the utilities' data processes need to recognize that more granular data and forecasts will be needed in the future to identify beneficial locations for DER.⁴¹ Moreover, the PSC directed New York State utilities to include sufficient information in their

⁴⁰ Case 14-E-0423, Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Order Instituting Proceeding Regarding Dynamic Load Management Directing Tariff Filings (issued December 15, 2014), Appendix A, p. 2.

⁴¹ Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Order Adopting Distributed System Implementation Plan Guidance (issued July 28, 2016), p. 27.

Distributed System Integration Plans (DSIPs) and BCA handbooks to inform the developing DER market of system conditions, needs, and granular marginal values so that any solicitations for alternative solutions will be robust.⁴²

More recently, the Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs recommends the sunset of LSRV compensation.⁴³ The Department noted the need for continued, planned and focused improvement of marginal cost studies as a critical aspect of hastening the transition to an increasingly distributed grid. Staff noted that the forum for that improvement and associated deliberations should appropriately take place as part of the Utility DSIP proceeding. The PSC Order specified that such deliberations “should include substantial discussion of utility costs and system data, particularly capital investment plans (driven largely by expected load growth) which are direct inputs to the marginal cost studies.”⁴⁴

Unlocking locational value as it relates to developing DERs is crucial to achieving REV objectives. A locational study is necessary to accomplish this. DPS recommends that PSEG LI pursue a locational value study with the following modifications. PSEG LI should further define the scope and the objectives of the study. The proposed workplan should be revised in collaboration with DPS Staff and should include at a minimum, solicitation of stakeholder/public input, as well as, lessons learned from the Joint Utilities regarding the implementation of their own locational value studies. DPS also recommends that PSEG LI report on the status of the study in its next annual Utility 2.0 filing. As part of PSEG LI’s proposal to participate with the Joint Utilities in stakeholder proceedings, PSEG LI should consider how to share the results of the study with the Joint Utilities.

Public comments pointed out the need for a clear articulation of project needs, including GIS based map data, and accurate local grid descriptions, which are necessary to engineer targeted solutions. For instance, similarly to the discussion of PSEG LI’s efforts in rate modernization, PSEG LI should also consider the extent to which the locational value study may inform efforts such as a DCFC mapping study in 2019 to determine sites suitable for chargers. NYPA stated in its comments that the mapping study should cover the entire service territory with granularity to the feeder level. To the extent possible, information from the study should also be made available to developers to help in their selection of sites.

As stated above, the Department recommends that PSEG LI pursue the locational value study with the modifications discussed. The study is a key component to inform PSEG LI’s other Utility 2.0 endeavors being pursued in the near and future term.

Non-Wire Solutions Analysis Tool

⁴² Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).

⁴³ Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs (issued July 26, 2018), p. 8.

⁴⁴ Id., p. 3.

PSEG LI proposes to develop a Non-Wire Solutions (NWS) planning tool to evaluate NWS and DER portfolio projects for cost-effectiveness. PSEG LI projects cost of approximately \$0.5 million of O&M in 2019. The Department recommends PSEG LI pursue the analysis tool as proposed.

PSEG LI's NWS tool proposes to more effectively identify NWS, and assess the cost effectiveness of these solutions. PSEG LI states that the primary functions of the tool include testing projects utilizing the PSC's protocols outlined in the NY BCA Order to value NWS projects, generating daily load shape profiles by day type (e.g., peak day, weekday, weekend/holiday) for baseline consumption, assessing NWS consumption, assessing the resulting savings, whether hourly load shapes are available, and estimating savings contributions based upon system need durations, frequency of need, and other econometric input factors.⁴⁵ As proposed, the tool is a standalone mechanism with respect to other Utility 2.0 projects and use of such a tool is intended to reduce future expenditures.

The Department is firmly in favor of developing NWA solutions considering the constantly increasing cost of capital construction solutions. Moreover, the tool implements the PSC's BCA protocols as part of PSEG LI's efforts to pursue NWS. While PSEG LI has pursued NWA solutions, the ability to identify projects more effectively is certainly informed by the development of analysis tool. The Department recommends that PSEG LI develop the tool and expand upon it to further future program goals in upcoming Utility 2.0 filings. In addition, as the program is developed, PSEG LI should consider how to integrate the Company's system planning group as leading the NWS planning endeavor. PSEG LI should leverage its experience with previous NWS projects and confer with DPS Staff to create a useful analytical tool, prior to expending resources to this effort.

As stated above, DPS recommends that PSEG LI should pursue this proposal as filed.

Budgeting and Funding

PSEG LI proposes to recover Capital expenditures of \$74.5m for 2019, \$52.1m for 2020, \$56.0m for 2021 and \$56.9m for 2022. PSEG LI proposes to recover gross O&M costs of Utility 2.0 programs in the amount of \$21.0m for 2019, \$18.0m for 2020, \$19.7m for 2021 and \$20.9m for 2022 and Fuel and Purchase Power expenditures of \$43k, \$79.7k, \$180.5k, and \$241k for 2019, 2020, 2021 and 2022, respectively. The total cost of PSEG LI's 2018 proposal is approximately \$321m over four years, 2019 through 2022. The total cost of PSEG LI's proposal, as reflected by the Department's recommendations, is approximately \$306.6 million through 2022.

DPS recommends that PSEG LI track project costs and benefits, and reconcile these figures on an annual basis as part of the next Utility 2.0 filing. DPS recommends that all program costs be updated with actual cost. Ratepayers should receive the benefits obtained by

⁴⁵ Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).

PSEG LI as a result of its filing. DPS recommends that any overfunding or underspending be applied exclusively to future Utility 2.0 funding requests. The need for additional funding due to underbudgeting should be evaluated as part of the Department's review of future Utility 2.0 filings. DPS recommends that PSEG LI and LIPA appropriately justify the need for additional funding beyond the levels projected in the 2018 Utility 2.0 filing if such additional funding is needed to complete projects contained herein.

DPS recommends that LIPA and PSEG LI work with Department Staff to verify the amount of funding corresponding to the recommended 2018 Utility 2.0 plan and to develop a financial schedule with DPS review to timely and accurate track of costs and savings. The financial schedule should form the basis for project cost tracking and should be created for use as well in future Utility 2.0 filings. DPS recommends that amendment of the model or functions contained in the schedule be implemented upon agreement by DPS, LIPA, and PSEG LI.

Conclusion

The Department recommends that PSEG LI and LIPA proceed with the proposed 2018 Utility 2.0 Plan to the extent discussed above. Smart Meter Deployment, Rate Modernization, the Super Saver program, Energy Storage, the Distribute Platform Projects and enhancements to PSEG LI's Electric Vehicle programs will provide tangible benefits for Long Island ratepayers. As these programs progress, and other programs are improved or developed in future Utility 2.0 proposals, the Department expects that LIPA and PSEG LI will continue to make progress, in accordance with the LIPA Reform Act, with respect to energy efficiency, distributed generation and advanced grid technology programs, the goals of REV, the CES, Renewable Generation, and Energy Storage. DPS looks forward to continuing to work with PSEG LI and LIPA to achieve these goals.

Sincerely,



John B. Rhodes,
Chair

CC: Thomas Falcone, LIPA Chief Executive Officer
Anna Chacko, LIPA General Counsel and Secretary
Dan Eichorn, PSEG LI President and Chief Operating Officer
Guy Mazza, DPS LI Director

I. General Information (continued):**C. General Terms and Conditions (continued):****20. Low Income Program Discount****a) Customer Requirements and Eligibility**

- (1) Customers served under Service Classifications No. 1 and Service Classification No.1 VMRP who provide documentation of enrollment in a qualifying program as listed in Section I.B (Qualifying Low Income Customer) and are eligible for a fixed discount on their bill.
- (2) Eligibility and enrollment must be renewed each year. To the extent that the Authority can automatically determine a Qualifying Low Income Customer's continued eligibility, the customer will not need to re-apply.
- (3) Qualifying Low Income Customers whose continued eligibility cannot be automatically determined will be notified by the Authority as their enrollments expire. The Authority will allow such customers four (4) months from the expiration of their enrollments (the "Grace Period") to complete the renewal process. During the Grace Period, Qualifying Low Income Customers will continue to receive discounted charges. Qualifying Low Income Customers who do not complete the renewal process within the Grace Period and whose continued eligibility cannot be automatically determined by the Authority will become ineligible for the discounted charges until the renewal process is successfully completed.
- (4) The Authority may in its sole discretion limit participation in Long Island Choice by Qualifying Low Income Customers (defined in Section I.B above) as needed for consistency with New York State policy as set forth in Orders of the Public Service Commission.

b) Discounts

- (1) The Tier 1 discount is available to all Qualifying Low Income Customers. Customers that have received a HEAP benefit plus one (1) add-on shall receive the Tier 2 discount. Customers that have received a HEAP benefit plus two (2) add-ons shall receive the Tier 3 discount. The Tier 4 discount is reserved for customers with Direct Voucher/Guaranteed Payment. HEAP recipients receive add-ons for households with a vulnerable individual (household member who is age 60 or older, under age 6 or permanently disabled) and/or if the household's gross income meets HEAP Tier 1 income guideline.

Tier	Electric Heat (Rates 580 and 880)	Electric Non-Heat (Rates 180, 380 and 188)
1	\$.67 .83 per day	\$.67 .83 per day
2	\$1.33 1.53 per day	\$.67 .83 per day
3	\$2.00 2.17 per day	\$.67 .83 per day
4	\$1.40 1.60 per day	\$1.40 1.60 per day

ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:**J. Revenue Decoupling Mechanism****Definitions (continue):**

- a) Retail Customers participating in the Long Island Choice or Green Choice program are subject to the Revenue Decoupling Mechanism according to their base rate Service Classification.
- b) The Revenue Decoupling Mechanism does not apply to:
 - (1) Energy Service Companies (ESCOs) receiving service under Service Classification No. 14.
 - (2) Service Classification Nos. 5, 7, 7A and 10 (Rate Codes 980, 780, 781, 782, 1580, 1581).
 - (3) Service Classification Nos. 11, 12, and 13 (Rate Codes 289, 680, 681, 278).
 - (4) All load delivered under the Empire Zone Program, Excelsior Jobs Program, Manufacturer's Competitiveness, Business Attraction/Expansion Program, Business Incubation, and Recharge New York Programs.
- c) Annual Approved Delivery Service Revenues subject to the Revenue Decoupling Mechanism are:

The Delivery Service Revenues approved by the Authority for each Service Classification for each month, starting on April 1st 2015. Delivery Service Revenues exclude adjustments to rates and charges which include: the Power Supply Charge, Distributed Energy Resources Cost Recovery Rate, New York State Assessment Factor, Shoreham Property Tax Settlement Factor, Visual Benefits Assessment Rate, Charges to Recover PILOT Payments, the Revenue Decoupling Mechanism, and the Delivery Service Adjustment.
- d) Revenues for the calendar year are set forth in the approved LIPA budget, and are revised each December for the upcoming calendar year.
- e) Actual booked Delivery Service Revenues are, for the purposes of Revenue Decoupling Mechanism, booked revenues for all Service Classifications for each month in the calendar year as it relates to the Service Charge, Meter Charge, Demand Charge (per kW), Reactive Demand Charge (per kvar), and the Energy Charge for delivery (per kWh).

ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:**J. Revenue Decoupling Mechanism****3. Cost Recovery Period and Method**

a) For each Service Classification group subject to the Revenue Decoupling Mechanism:

(1) The difference between actual booked Delivery Service Revenues and approved Delivery Service Revenues will be reviewed monthly and accrued for refund to or recovery from the applicable Service Classification groups.

(2) After September 30th of each year, -the cumulative revenue variance as of September 30th will be identified for each of the four participating Service Classification groups, and the refund or surcharge amount that is due to or from each of the four participating Service Classification groups will be calculated.

(3) For the calendar year beginning on January 1st, 2017 and each subsequent calendar year, the revenue variance estimated through December 31st of ~~that~~ the coming year will be calculated and included in the refund or surcharge amount applied to the participating Service Classification groups.

a. The revenue variance for the coming year will be calculated based on the actual variance from the prior twelve (12) months at the time the Revenue Decoupling Mechanism is calculated.

b. In the event of a change to the Delivery Rates based on the implementation of a new sales forecast, which would mitigate the unknown variance in the coming year, subparagraph J.3.a).(3) may be fully or partially suspended as determined by the Authority.

(4) Any revenue variance associated with the actual booked Delivery Service Revenues of the non-participating customer load as noted in Section VII. J.2.f) and any revenue variance associated with actual booked revenues from low income discounts will be allocated proportionately to the four Service Classification groups participating in the Revenue Decoupling Mechanism based upon the actual booked Delivery Service Revenue for each Service Classification group during the twelve (12) months ending September 30th.

(5) The refund or surcharge amount for each Service Classification group will be divided by the forecasted Delivery Service Revenues for each Service Classification group for the upcoming calendar year to develop the percentage of Delivery Service Revenues for each Service Classification group.

(6) Beginning in 2017, the surcharges or refunds percentages will be applied, to the Delivery Service charges associated with each customer in the four participating Service Classification groups, for the 12-month periods beginning January 1st of each calendar year.

VIII. SERVICE CLASSIFICATIONS: (continued):**A. SERVICE CLASSIFICATION NO. 1 - Residential Service (continued):
(Rate Codes: 180, 380, 480, 481, 580, 880)****3. Rates and Charges per Meter:****a) Schedule of Rates**

The rates for this service code are set forth below.

<u>Rate Code 180</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per Day	\$. 3600 <u>4000</u>	\$. 3600 <u>4000</u>
Energy Charge per kWh per month		
First 250 kWh @	\$. 0714 <u>0786</u>	\$. 0714 <u>0786</u>
Over 250 kWh @	\$. 0899 <u>0993</u>	\$. 0714 <u>0786</u>
 <u>Rate Code 380 (Water Heating)</u>	 <u>June to September Inclusive</u>	 <u>October to May Inclusive</u>
Service Charge per Day	\$. 3600 <u>4000</u>	\$. 3600 <u>4000</u>
Energy Charge per kWh per month	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
First 250 kWh @	\$. 0714 <u>0786</u>	\$. 0714 <u>0786</u>
Next 150 kWh @	\$. 0899 <u>0993</u>	\$. 0714 <u>0786</u>
Next 400 kWh @	\$. 0684 <u>0839</u>	\$. 0572 <u>0679</u>
Over 800 kWh @	\$. 0899 <u>0993</u>	\$. 0714 <u>0786</u>

VIII. SERVICE CLASSIFICATIONS: (continued):**A. SERVICE CLASSIFICATION NO. 1 - Residential Service (continued):****(Rate Codes: 180, 380, 480, 481, 580, 880)****Rates and Charges per Meter (continued):**

<u>Rate Code 580 (Space Heating)</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per Day	\$. 3600 <u>4000</u>	\$. 3600 <u>4000</u>
Energy Charge per kWh per month		
First 250 kWh @	\$. 0711 <u>0786</u>	\$. 0711 <u>0786</u>
Next 150 kWh @	\$. 0899 <u>0993</u>	\$. 0711 <u>0786</u>
Over 400 kWh @	\$. 0899 <u>0993</u>	\$. 0401 <u>0443</u>
<u>Rate Code 880 (Space and Water Heating)</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per Day	\$. 3600 <u>4000</u>	\$. 3600 <u>4000</u>
Energy Charge per kWh per month		
First 250 kWh @	\$. 0711 <u>0786</u>	\$. 0711 <u>0786</u>
Next 150 kWh @	\$. 0899 <u>0993</u>	\$. 0711 <u>0786</u>
Next 400 kWh @	\$. 0684 <u>0839</u>	\$. 0401 <u>0443</u>
Over 800 kWh @	\$. 0899 <u>0993</u>	\$. 0401 <u>0443</u>
<u>Rate Code 480, 481</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per day	\$. 3200 <u>3600</u>	\$. 3200 <u>3600</u>
Energy Charge per kWh per month		
12:00 midnight to 7:00 a.m. (Standard Time) or	\$. 0124 <u>0137</u>	\$. 0124 <u>0137</u>
10:00 p.m. to 10:00 a.m. (Standard Time)	\$. 0138 <u>0153</u>	\$. 0138 <u>0153</u>

VIII. SERVICE CLASSIFICATIONS (continued):**B. SERVICE CLASSIFICATION NO. 1-VMRP (L)****Voluntary Large Residential Service with Multiple Rate Periods (continued):**
(Rate Codes: 181, 182, 184)3. Rates and Charges per Meter:a) Schedule of Rates

The rates for this service code are found below.

<u>All Rate Codes</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per Day	\$1.65 <u>1.82</u>	\$1.65 <u>1.82</u>
<u>Rate Codes 184 – Rate 1</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Energy Charge per kWh		
Daylight Savings Time 8 p.m. to 10 a.m., and Saturday and Sunday	<u>Period 1</u>	<u>Period 2</u>
First 125 kWh @	\$.0220 <u>0.243</u>	\$.0220 <u>0.243</u>
Over 125 kWh @	\$.0220 <u>0.243</u>	\$.0220 <u>0.243</u>
Daylight Savings Time 10 a.m. to 8 p.m. Weekdays	<u>Period 3</u>	<u>Period 4</u>
First 125 kWh @	\$.0675 <u>0.746</u>	\$.0675 <u>0.746</u>
Over 125 kWh @	\$.2452 <u>2.712</u>	\$.0688 <u>0.761</u>

VIII. SERVICE CLASSIFICATIONS (continued):**B. SERVICE CLASSIFICATION NO. 1-VMRP (L)****Voluntary Large Residential Service with Multiple Rate Periods (continued):****(Rate Codes: 181, 182, 184)****Rates and Charges per Meter (continued):**

	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
<u>Rate Codes 181 - Rate 2</u>		
Energy Charge per kWh		
Daylight Savings Time*		
8 p.m. to 10 a.m., and		
Saturday and Sunday		
	<u>Period 1</u>	<u>Period 2</u>
First 125 kWh @	\$. 04820533	\$. 04820533
Over 125 kWh @	\$. 04820533	\$. 04820533
Daylight Savings Time*		
10 a.m. to 8 p.m.		
Weekdays	<u>Period 3</u>	<u>Period 4</u>
First 125 kWh @	\$. 04820533	\$. 04820533
Over 125 kWh @	\$. 12041328	\$. 08670959
	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
<u>Rate Codes 182 - Rate 3</u>		
Energy Charge per kWh		
Daylight Savings Time*		
8 p.m. to 10 a.m., and		
Saturday and Sunday		
	<u>Period 1</u>	<u>Period 2</u>
First 125 kWh @	\$. 04850536	\$. 04850536
Over 125 kWh @	\$. 04850536	\$. 03140347
Daylight Savings Time*		
10 a.m. to 8 p.m.		
Weekdays	<u>Period 3</u>	<u>Period 4</u>
First 125 kWh @	\$. 04850536	\$. 04850536
Over 125 kWh @	\$. 12101338	\$. 03160349

* See paragraph IV.A.10 "Daylight Savings Time" Leaf No. 99.

VIII. SERVICE CLASSIFICATIONS (continued):**C. SERVICE CLASSIFICATION NO. 1-VMRP(S)****Voluntary Small Residential Service With Multiple Rate Periods (continued):**
(Rate Code: 188)3. Rates and Charges per Meter:a) Schedule of Rates

The rates for this service code are found below.

<u>All Rate Codes</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per day	\$. 3600 <u>4000</u>	\$. 3600 <u>4000</u>
Meter Charge per day	\$. 4000 <u>1100</u>	\$. 4000 <u>1100</u>
<u>Rate Codes 188</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Energy Charge per kWh		
Daylight Savings Time* 8 p.m. to 10 a.m., and Saturday and Sunday	<u>Period 1</u>	<u>Period 2</u>
	\$. 0455 <u>0503</u>	\$. 0296 <u>0327</u>
Daylight Savings Time* 10 a.m. to 8 p.m. Weekdays	<u>Period 3</u>	<u>Period 4</u>
	\$. 2880 <u>3185</u>	\$. 0804 <u>0886</u>

* See Paragraph IV. A. 10. "Daylight Savings Time" on leaf No. 99.

b) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, Revenue Decoupling Mechanism, the Securitization Offset Charge, and the Delivery Service Adjustment.

4. Minimum Charge

The Minimum Charge is the Service and Meter Charges, plus Adjustments to Rates and Charges.

VIII. SERVICE CLASSIFICATIONS (continued):**D. SERVICE CLASSIFICATION NO. 2 - General Service - Small:
(Rate Code: 280)****1. Who Is Eligible**

- a) Customers who will use the service for purposes other than Residential, when the Authority estimates that the Applicant's demand will be less than 7 kW, subject to Special Provision 8.c) below. The Authority may bill the Customer on a metered or unmetered basis.
- b) A Customer, as described in a. above, that has the option under Service Classification Nos. 12 – Backup and Supplemental Service, of choosing to pay the rates and charges associated with a different Service Classification.

2. Who Is Not Eligible

Traffic Signals, caution signals and operating control equipment for all such signals are no eligible for service under this Service Classification.

3. Character of Service

- a) Continuous, 60 hertz, alternating current.
- b) Radial secondary service at approximately 120/208, 120/240, or 277/480 volts, single or three phase; network system 120/208 or 277/480 volts, single or three phase; depending on the size and characteristics of the load and the circuit supplying the service.

4. Rates and Charges per Meter:**a) Schedule of Rates**

The rates for this service are set forth below.

<u>Rate Code 280</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per day	\$. 3600 <u>4000</u>	\$. 3600 <u>4000</u>
Energy Charge per kWh	\$. 0976 <u>1078</u>	\$. 0787 <u>0869</u>

VIII. SERVICE CLASSIFICATIONS (continued):**E. SERVICE CLASSIFICATION NO. 2-VMRP****Voluntary Small General Service With Multiple Rate Periods: (continued)**
(Rate Code: 288)3. Rates and Charges per Meter:a) Schedule of Rates

The rates for this service code are found below

<u>Rate Code 288</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Meter Charge per day	\$. 4000 <u>1100</u>	\$. 4000 <u>1100</u>
Service Charge per day	\$. 3600 <u>4000</u>	\$. 3600 <u>4000</u>
Energy Charge per kWh		
Daylight Savings Time 8 p.m. to 10 a.m., and Saturday and Sunday	<u>Period 1</u> \$. 0455 <u>0503</u>	<u>Period 2</u> \$. 0296 <u>0327</u>
Daylight Savings Time 10 a.m. to 8 p.m. Weekdays	<u>Period 3</u> \$. 2880 <u>3185</u>	<u>Period 4</u> \$. 0804 <u>0886</u>

b) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, Revenue Decoupling Mechanism, the Securitization Offset Charge, and the Delivery Service Adjustment.

4. Minimum Charge

The Minimum Charge is the Service and Meter Charge, plus Adjustments to Rates and Charges.

5. Terms of Payment

The Customer shall pay the balance due in cash, including checks and money orders, on receiving the bill. Late payments shall be subject to Late Payment Charges.

VIII. SERVICE CLASSIFICATIONS (continued):**F. SERVICE CLASSIFICATION NO. 2-L - General Service – Large (continued):
(Rate Codes: 281, 283, 291)****3. Rates and Charges per Meter:****a) Schedule of Rates**

The rates for this service code are set forth below.

Secondary Service

<u>Rate Code 281</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per day	\$1.94 <u>2.11</u>	\$1.94 <u>2.11</u>
Demand Charge per kW of demand	\$14.54 <u>16.08</u>	\$13.33 <u>14.74</u>
Energy Charge per kWh	\$0.0249 <u>0.0276</u>	\$0.0400 <u>0.111</u>

Primary Service

<u>Rate Code 281</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Service Charge per day	\$1.94 <u>2.11</u>	\$1.94 <u>2.11</u>
Demand Charge per kW of demand	\$13.58 <u>15.01</u>	\$12.39 <u>13.70</u>
Energy Charge per kWh	\$0.0243 <u>0.0270</u>	\$0.0094 <u>0.105</u>
Demand Charge per kvar of Reactive Demand	\$0.27	\$0.27

b) Rate Code 283 - Seasonal

The following changes to 3.a) above apply to Customers who terminate service for at least four (4) continuous months from October through May and submit a signed Application:

VIII. SERVICE CLASSIFICATIONS (continued):**G. SERVICE CLASSIFICATION NO. 2L - VMRP****Voluntary Large Demand Metered Service With Multiple Rate Periods (continued):
(Rate Codes: 282 and M282)**3. Rates and Charges per Meter per Month:a) Schedule of Rates

The rates for this service code are set forth below.

Rate Code 282-(Secondary)*

Service Charge per day	\$1.57 <u>1.74</u>
------------------------	-------------------------------

Meter Charge per day	\$.2500 <u>2800</u>
----------------------	--------------------------------

Rate Periods**

1

2

3

Off-Peak
all year

On-Peak*
June - Sept.
weekdays

Intermediate
all
other
hours

11 p.m.
to 7 a.m.

12 noon
to 8 p.m.

Demand Charge per kW
Total of 3 Rate Periods

none

~~\$49.43~~ 54.66~~\$4.24~~ 4.69

Energy Charge per kWh
Total of 3 Rate Periods

~~\$.0030~~ 0033~~\$.0216~~ 0239~~\$.0184~~ 0200

Minimum Demand Charge
per Meter per kW
per Rate Period

none

\$55.58

\$6.74

*For Rate Code M282 (Secondary), the modified peak period is from 3 p.m. to 8 p.m.

** See Paragraph IV.A.10, "Daylight Savings Time", on Leaf No. 99.

VIII. SERVICE CLASSIFICATIONS (continued):**F. SERVICE CLASSIFICATION NO. 2L - VMRP****Voluntary Large Demand Metered Service With Multiple Rate Periods (continued):****(Rate Codes: 282 and M282)****Rates and Charges per Meter per Month (continued):**Rate Code 282-(Primary)Service Charge per day \$~~1.57~~1.74Meter Charge per day \$.~~7500~~8400Rate Periods**

1

2

3

Off-Peak
all yearOn-Peak*
June - Sept.
weekdays
12 noon
to 8 p.m.Intermediate
all
other
hours11 p.m.
to 7 a.m.

Demand Charge per kW

Total of 3 Rate Periods

none

\$~~46.98~~51.95\$~~4.06~~4.49

Energy Charge per kWh

Total of 3 Rate Periods

\$~~.0027~~0030\$~~.0194~~0215\$~~.0464~~0181Demand Charge per kvar
of Reactive Demand

Total of 3 Rate Periods

none

\$.27

\$.27

Minimum Demand Charge
per Meter per kW
per Rate Period

none

\$52.91

\$6.44

* For Rate Code M282 (Primary), the modified peak period is from 3 p.m. to 8 p.m.

**See Paragraph IV.A.10, "Daylight Savings Time", on Leaf No. 99.

b) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, Revenue Decoupling Mechanism, the Securitization Offset Charge, and the Delivery Service Adjustment.

4. Minimum Charge - All Rate Codes

The monthly Minimum Charge is the sum of the Service and Meter Charges, and may include an annual Demand Charge (See 6.below), plus Adjustments to Rates and Charges.

VIII. SERVICE CLASSIFICATIONS (continued):**I. SERVICE CLASSIFICATION NO. 2 - MRP****Large General and Industrial Service With Multiple Rate Periods (continued):****(Rate Codes: 284, 285, M284, M285)****Character of Service (continued):**

- a) The Authority may consider loads with a minimum estimated demand of 10,000 kW for service at 69,000 volts or higher.
- b) The Primary Rate will also apply to Customers served at 23,000 or 33,000 volts.
- c) The Transmission Rate will apply to Customers served at 69,000 volts or higher.

2. Rates and Charges per Meter per Month:**a) Schedule of Rates**

The rates for the service code are set forth below.

<u>Rate Code 285</u>	<u>Secondary</u>	<u>Primary</u>	<u>Transmission</u>
Service Charge per day \$ 8.969.91	\$ 8.549.44	\$ 8.969.91	
Meter Charge per day \$ 6.507.19	\$ 2.502.76	\$ 6.507.19	
<u>Rate Periods**</u>			
	<u>1</u> Off-Peak all year midnight to 7 a.m.	<u>2</u> On-Peak * June-Sept. except Sundays 10 a.m. 10 a.m. to 10 p.m.	<u>3</u> Intermediate all other hours
<u>Demand Charge per kW</u>			
Secondary	none	\$ 24.3926.97	\$ 5.846.43
Primary	none	\$ 20.9323.15	\$ 5.135.67
Transmission	none	\$ 17.3019.13	\$ 4.214.65
<u>Energy Charge per kWh</u>			
Secondary	\$.00500055	\$.03230357	
Primary	\$.02060228	\$.00290032	\$.02840311
Transmission	\$.01840200	\$.00280032	\$.02630291
	\$.01700188		
<u>Minimum Demand Charge</u> per Meter per kW per Rate Period			
Secondary	none	\$33.50	\$9.21
Primary	none	\$28.76	\$8.13
Transmission	none	\$23.79	\$6.68

*For Rate M285, the modified peak period is from 3 p.m. to 10 p.m. on weekdays (Monday – Friday)

** See Paragraph IV.A.10, "Daylight Savings Time", on Leaf No.99.

VIII. SERVICE CLASSIFICATIONS (continued):**I. SERVICE CLASSIFICATION NO. 2 - MRP****Large General and Industrial Service With Multiple Rate Periods (continued):****(Rate Codes: 284, 285, M284, M285)****Rates and Charges per Meter per Month (continued):**

<u>Rate Code 284</u>	<u>Secondary</u>	<u>Primary</u>	<u>Transmission</u>
Service Charge per day \$8.969.91	\$8.549.44	\$8.969.91	
Meter Charge per day \$6.507.19	\$2.502.76	\$6.507.19	
<u>Rate Periods**</u>			
	1	2	3
	Off-Peak all year 11 p.m. to 7 a.m.	On-Peak * June - Sept weekdays 12 noon to 8 p.m.	Intermediate all other hours
<u>Demand Charge per kW</u>			
Secondary	none	\$47.2752.27	\$4.735.23
Primary	none	\$42.4446.93	\$4.244.69
Transmission	none	\$34.7235.08	\$3.463.50
<u>Energy Charge per kWh</u>			
Secondary	\$.0001	\$.02760305	\$.01780197
Primary	\$.0001	\$.01980219	\$.00360040
Transmission	\$.0001	\$.01870207	\$.00340038
<u>Minimum Demand Charge</u> per Meter per kW per Rate Period			
Secondary	none	\$54.99	\$7.25
Primary	none	\$49.57	\$6.68
Transmission	none	\$36.88	\$5.06

* For Rate Code M284, the modified peak period is from 3 p.m. to 8 p.m.

** See Paragraph IV.A.10, "Daylight Savings Time", on Leaf No. 99.

b) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, Revenue Decoupling Mechanism, the Securitization Offset Charge, and the Delivery Service Adjustment.

VIII. SERVICE CLASSIFICATIONS (continued):**K. SERVICE CLASSIFICATION NO. 5**
Traffic Signal Lighting (continued):
(Rate Code: 980)**4. Definition of Control Mechanism for Billing Purposes:**

A control mechanism is a device that controls the signal lights and other traffic/pedestrian equipment at an intersection.

5. Rates and Charges**a) Rates per Signal Face of Light per Month**

~~\$6.96~~7.70 per control mechanism per month.

~~\$2.06~~2.28 per incandescent signal face per month.

~~\$2.84~~3.14 per LED signal face per month

b) Adjustment to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, the Securitization Offset Charge, and the Delivery Service Adjustment.

6. Terms of Payment

The Customer shall pay the balance due in cash, including checks and money orders, on receiving the bill. Late payments shall be subject to Late Payment Charges.

7. Term of Service

- a) The Authority will provide service to the Customer until service is terminated either by the Customer or the Authority.
- b) The Customer shall give the Authority thirty (30) days written notice when requesting termination of service.
- c) The Authority may terminate service to the Customer in accordance with the provisions of this Tariff, after giving the Customer thirty (30) days written notice.

VIII. SERVICE CLASSIFICATIONS (continued):**J. SERVICE CLASSIFICATION NO. 7****Outdoor Area Lighting:**
(Rate Code: 780)**1. Who Is Eligible**

Customers who used this service for outdoor lighting before December 5, 1986, provided:

- a) Suitable overhead distribution facilities exist, except,
- b) When only one (1) span of overhead secondary cable per lighting fixture is needed. In such cases, the Authority will provide the cable on existing poles.

2. Character of Service

- a) Unmetered, single-phase, 60 hertz, alternating current supplied to Authority-owned, operated, and maintained lighting facilities, and
- b) Provided for approximately 4,210 hours per year (4,222 for a leap year), at suitable voltages chosen by the Authority, and
- c) Provided to mercury vapor and incandescent lighting facilities.

3. Rates and Charges**a) Rates per Mercury Vapor Facility per Month**

<u>Type Luminaire</u>	<u>Approximate Lumens</u>	<u>Total Watts</u>	<u>Monthly Rates</u>
Area Light	7,000	200	\$12.86 14.22
Area Light	21,000	455	\$18.24 20.17
Flood Light	21,000	455	\$19.90 22.01
Flood Light	52,000	1,100	\$41.76 46.18

b) Rates per Incandescent Facility per Month

<u>Type Luminaire</u>	<u>Approximate Lumens</u>	<u>Total Watts</u>	<u>Monthly Rates</u>
Flood Light	100 c.p.	92	\$5.26 5.82
Flood Light	250 c.p.	189	\$8.97 9.92

c) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, the Securitization Offset Charge, and the Delivery Service Adjustment.

VIII. SERVICE CLASSIFICATIONS (continued):**M. SERVICE CLASSIFICATION NO. 7A****Outdoor Area Lighting - HPS (High Pressure Sodium) and MH (Metal Halide):**
(Rate Codes: 781, 782)1. Who Is Eligible

Customers who will use this service for outdoor lighting, provided:

- a) Suitable overhead distribution facilities exist, except
- b) When only one (1) span of overhead secondary cable per lighting fixture is needed. In such cases, the Authority will provide the cable on existing poles. Charges for additional cable and poles are given below.

2. Character of Service

- d) Unmetered, single-phase, 60 hertz, alternating current supplied to Authority-owned, operated, and maintained lighting facilities, and
- e) Provided for approximately 4,090 hours per year (4,102 for a leap year), at suitable voltages chosen by the Authority, and
- f) Provided to high pressure sodium and metal halide facilities.

3. Rates and Chargesa) Rates per Lighting Facility per Month

<u>Lamp Type</u>	<u>Type Luminaire</u>	<u>Approximate Lumens</u>	<u>Total Watts</u>	<u>Monthly Rates</u>
High Pressure Sodium*	Area Light	6,400	108	\$18.70 <u>20.68</u>
High Pressure Sodium*	Flood Light	27,500	309	\$22.94 <u>25.37</u>
High Pressure Sodium*	Flood Light	50,000	476	\$30.48 <u>33.71</u>
Metal Halide*	Flood Light	36,000	453	\$31.01 <u>34.29</u>
Metal Halide*	Flood Light	110,000	1093	\$33.78 <u>37.36</u>
High Pressure Sodium	Full Cut-off	4,000	63	\$25.42 <u>28.11</u>
High Pressure Sodium	Full Cut-off	6,300	91	\$25.49 <u>28.19</u>
High Pressure Sodium	Full Cut-off	9,500	128	\$25.85 <u>28.59</u>

*Commencing October 1, 2003, not available for new installations or replacements.

VIII. SERVICE CLASSIFICATIONS (continued):**M. SERVICE CLASSIFICATION NO. 7A****Outdoor Area Lighting - HPS (High Pressure Sodium) and MH (Metal Halide) (continued):**
(Rate Codes: 781, 782)**Rates and Charges (continued):**

<u>Lamp Type</u>	<u>Type Luminaire</u>	<u>Approximate Lumens</u>	<u>Total Watts</u>	<u>Monthly Rates</u>
High Pressure Sodium	Full Cut-off	28,500	305	\$28.97 <u>\$32.04</u>
High Pressure Sodium	Full Cut-off	50,000	455	\$37.32 <u>\$41.27</u>
Metal Halide	Full Cut-off	20,500	288	\$29.42 <u>\$32.20</u>
Metal Halide	Full Cut-off	36,000	455	\$37.32 <u>\$41.27</u>

- b) The charge for Additional Overhead Secondary Cable and Poles dedicated to the Customer is ~~\$14.57~~\$16.11 per span per month.

c) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, the Securitization Offset Charge, and the Delivery Service Adjustment.

4. Minimum Charge

The monthly Minimum Charge is the facilities charge computed under the rates in 3 a), b) and c) above for the number of lighting facilities in place on the billing date.

5. Terms of Payment

The Customer shall pay the balance due in cash, including checks and money orders, on receiving the bill. Late payments shall be subject to Late Payment Charges.

6. Term of Service

- The Term of Service is two (2) years, and the Authority will provide service to the Customer until service is terminated either by the Customer or the Authority.
- The Customer shall give the Authority five (5) days written notice when requesting termination of service, after two (2) years from the start of service.
- The Authority may terminate service to the Customer in accordance with the provisions of this Tariff.
- The Authority may terminate service immediately if, for any reason, the Authority is not able to maintain the lines needed to supply the facility or is unable to maintain the facility.

VIII. SERVICE CLASSIFICATIONS (continued):**N. SERVICE CLASSIFICATION NO. 10****Public Street and Highway Lighting Energy and Connections:**
(Rate Codes: 1580, 1581)**1. Who Is Eligible**

- a) Customers who will use this service for lighting of public streets, highways, parks, parking fields, and similar areas where facilities are owned and maintained by governmental agencies or their agents, and
- b) The Authority will furnish service only after suitable agreements are signed that cover energy requirements and service connections.

2. Character of Service

- e) Unmetered, single-phase, 60 hertz, alternating current supplied to Customer-owned, operated, and maintained lighting facilities (a lighting facility includes luminaries, posts, supply circuits, and all associated equipment needed), and
- f) Provided at suitable voltages chosen by the Authority.

3. Rates and Charges

- a) The Energy Charge per Lighting Facility per Month is \$.~~0417~~0461 per kWh, for the monthly kWhs of unmetered lighting service specified in this Tariff.
- b) The Underground Connection Charge per Month is \$~~3.133~~3.46 per Energy Delivery Point serving one or more underground-supplied lighting facility as described in Special Provision 7.a. below.
- c) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, Delivery Service Adjustment, and the Securitization Offset Charge.

4. Minimum Charge

The monthly Minimum Charge is the total Underground Connection Charge, plus Adjustments to Rates and Charges.

5. Terms of Payment

The Customer shall pay the balance due in cash, including checks and money orders, on receiving the bill. Late payments shall be subject to Late Payment Charges.

VIII. SERVICE CLASSIFICATIONS (continued):**P. SERVICE CLASSIFICATION NO. 12****Back-Up and Supplemental Service (continued):**
(Rate Codes: 680, 681)**4. Character of Service**

- a) 60 hertz, single or three-phase alternating current.
- b) Service is metered at one standard delivery voltage, and the Authority will determine the site-specific characteristics and make the necessary adjustments to maintain that delivery voltage.

5. Rates and Charges for Backup and Supplemental Service

- a) Customers requiring Supplemental Service will pay the rates and charges under another suitable Service Classification. In this case, the Customer will comply with the terms of this Service Classification including the interconnection provision, that are in addition to, and do not conflict with the requirements of the suitable Service Classification.
 - (1) Customers that receive their non-Authority supply from the New York Power Authority (NYPA) under the Recharge NY program will be designated as Rate Code 680.
 - (2) Customers that are a Qualifying Facility under Part 292 of Title 18 of the Code of Federal Regulations, and choose to pay the rates under this Service Classification will be designated as Rate Code 681.
 - (3) Customers that are eligible for net metering pursuant to § 66 – j or § 66 – l of the Public Service Law will be designated with the rate code associated with that suitable Service Classification.
 - (4) Any Back-up Service provided in conjunction with Supplemental Service will be included with the usage and demand billed at the specified rates for Supplemental Service.
- b) Service Charge per Installation per Month (Rate Code 681)
 - (1) The Service Charge applies to all Back-Up Service except when this service is combined with Supplemental Service.

**Back-Up and
Supplemental Service**

Secondary Voltage (7 KW and less):	\$36.43 <u>40.29</u>
Secondary Voltage (Above 7 KW):	\$66.23 <u>73.24</u>
Primary Voltage:	\$109.29 <u>120.86</u>

VIII. SERVICE CLASSIFICATIONS (continued):**O. SERVICE CLASSIFICATION NO. 12****Back-Up and Supplemental Service (continued):****(Rate Codes: 680, 681)****Rates and Charges for Backup and Supplemental Service (continued):**

- (2) Customers taking service at the transmission voltage level shall pay the full cost of metering devices and any other Local Facilities as part of the Interconnection Charge (see 6. and 7. below) and will not pay a monthly Service Charge.
- c) Demand Charges for Distribution recover the costs of distribution facilities not paid for by the Customer as a lump sum payment or in the Service Charge.

Contract Demand Charge per KW per Month (Rate Code 681)

The Contract Demand Charge is paid monthly for capacity contracted for by Back-Up and Supplemental Service Customers taking service at the primary and secondary distribution levels, as described in Special Provision 11.e. below.

**Back-Up and
Supplemental Service**

Secondary: **~~\$2.76~~3.05**

Primary: **~~\$2.34~~2.55**

As-Used Demand Charge per KW per Month (Rate Code 681)

The As-Used Demand Charge is paid in addition to the Contract Demand Charge by Back-Up and Supplemental Service Customers taking service at the primary and secondary distribution levels for demand used during an interruption of the non-Authority supply. The demand billed shall be the highest demand during the month, but not less than one hundred percent (100%) of the highest demand in the last eleven (11) months.

**Back-Up and
Supplemental Service**

Secondary: **~~\$2.76~~3.05**

Primary: **~~\$2.34~~2.55**

VIII. SERVICE CLASSIFICATIONS (continued):**O. SERVICE CLASSIFICATION NO. 12****Back-Up and Supplemental Service (continued):****(Rate Codes: 680, 681)****Rates and Charges for Backup and Supplemental Service (continued):****d) Energy Charges per kWh (Rate Code 681)**

Energy Charges per kWh for both Back-Up and Supplemental Service

	<u>Rate Periods*</u>		
	1	2	3
	Midnight to 7 a.m. all year	June - Sept., except Sunday, 10 a.m. to 10 p.m.	All remaining hours
Secondary	\$. 0020 <u>0022</u>	\$. 2022 <u>2236</u>	\$. 0293 <u>0324</u>
Primary:	\$. 0010 <u>0011</u>	\$. 1953 <u>2160</u>	\$. 0272 <u>0301</u>
Transmission	\$.0001	\$. 1868 <u>2066</u>	\$. 0244 <u>0267</u>

* See Paragraph IV.A.10, "Daylight Savings Time", on Leaf No. 99.

e) Reactive Power Charge

Net Reactive Demand Charge per kvar = \$.27 for primary and transmission voltage services only, and applies from 7 a.m. through 11 p.m.

VIII. SERVICE CLASSIFICATIONS (continued):**S. SERVICE CLASSIFICATION NO. 16- AMI****Advanced Metering Initiative Pilot Service (continued):****(Rate Codes: M188, M288)****4. Residential and Small General Service Time-Differentiated Pricing**

Residential and Small General Service (rate codes 280 and 288) Customers participating in the Pilot Service will be charged the rates as stated below.

a) Schedule of Rates (Rate Code M188 and M288)

	June to September <u>Inclusive</u>	October to May <u>Inclusive</u>
Service Charge per day	\$. 3600 <u>4000</u>	\$. 3600 <u>4000</u>
	June to September <u>Inclusive</u>	October to May <u>Inclusive</u>
Energy Charge per kWh	<u>Period 1</u>	<u>Period 2</u>
7 p.m. to 2 p.m. weekdays and all day Saturday and Sunday	\$. 0469 <u>0519</u>	\$. 0469 <u>0519</u>
	<u>Period 3</u>	<u>Period 4</u>
2 p.m. to 7 p.m. Weekdays	\$. 3342 <u>3696</u>	\$. 4188 <u>1314</u>

All the terms and conditions will apply as described in the Customer's previous rate and Service Classification.

b) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, Revenue Decoupling Mechanism, the Securitization Offset Charge and the Delivery Service Adjustment.

c) Minimum Charge

The Minimum Charge is the Service charge, plus Adjustments to Rates and Charges.