PSEG LONG ISLAND

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Utility 2.0 Long Range Plan

Prepared for Long Island Power Authority

July 1, 2014

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Section 1: Executive Summary

1.1 Introduction

PSEG Long Island ("PSEG Long Island") submits this Utility 2.0 Long Range Plan ("Utility 2.0 Plan" or "Plan") in accordance with Public Authorities Law Section 1020-f(ee) and the Amended and Restated Operations Services Agreement ("OSA") dated December 31, 2013, for approval by the Long Island Power Authority ("the Authority" or "LIPA") and review by the New York State Department of Public Service ("DPS"). The OSA requires that PSEG Long Island submit this inaugural Utility 2.0 Plan no later than July 1, 2014, and annually thereafter.

PSEG Long Island, as the Authority's Service Provider, is committed to building an industry leading electric company dedicated to providing the people of Long Island and the Rockaways with exceptional customer service, best-in-class reliability and storm response, and a strong level of involvement in the communities in which its customers and employees live and work. This proposed Utility 2.0 Plan serves as the first in a series of annual long-range capital and operating plans contemplated by the Public Authorities Law and the OSA to help facilitate this objective.

While the Authority and New York State have been among our country's leaders in clean energy initiatives (discussed more fully in Section 2), PSEG Long Island believes that there remains untapped potential for targeted investments in demand side management. This includes increasing the use of energy efficiency, direct load control ("DLC") demand response, and distributed energy resources ("DER") such as distributed generation.

Long Island is a summer peaking system, primarily driven by residential cooling load. The peak drives power generation capacity needs and system investment decisions. Improving the energy efficiency of end use equipment (e.g., lighting, air conditioners, chillers and other equipment) can be the most cost-effective energy resource and provide significant savings for customers. Energy Efficiency resources can also be effective solutions to reduce greenhouse gas emissions, and were acknowledged as one of the "building blocks" for emissions reductions in the Environmental Protection Agency's recent Clean Power Plan announcement.[1] DLC can be a cost-effective

[1] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units"* 40 CFR Part 60 (June 2, 2014)

resource that specifically addresses peak demand, thereby improving system efficiency and providing a broader benefit in helping to avoid the costs of alternative solutions that are otherwise borne by all customers.

This Utility 2.0 Plan proposes targeted and programmatic investments with a focus on improving energy efficiency and reducing peak load to address emerging capacity and system needs across Long Island and in load pockets, particularly for customer segments that are often underserved, such as hospitals, low-income multifamily housing, and municipalities. We believe that there may be the potential to displace currently planned generation expansion through a reassessment of resource needs coupled with accelerating investments behind the meter at customer facilities in more energy efficient equipment with direct load control capability. This potential could be incorporated into a planning update scheduled for this fall and further assessed at that time.

As discussed further below, PSEG Long Island (or an affiliate) is prepared to invest up to $200M in these programs. This investment would be incremental to the continued funding of existing energy efficiency and renewable programs. We seek to implement these investments from 2015 through 2018 and allow PSEG Long Island to incorporate the demand savings from this program into current resource planning. Our proposal would incorporate cost recovery into the next rate case and defer repayment by the Authority for PSEG Long Island investments until 2016, supporting the current rate freeze. PSEG Long Island would amortize repayment over an extended period of time to mitigate rate impacts of the investments, which we expect to keep minimal and would be more than offset by cost savings. We may also explore the potential to reshape a portion of the existing energy efficency and renewable programs.

As required by the OSA and the Public Authorities Law, each year we will update the Utility 2.0 Plan and, as needed, refine the approach based on our experience, developing State and regulatory policies, input from a broad set of stakeholders, and ongoing development of new technologies. PSEG Long Island proposes to continue to provide periodic program reports to the Authority Trustees, and to utilize a third party to assess the deemed savings of projects and report on the effectiveness of the overall program.

Customers depend on reliable electric service more than they ever have before as electricity is an essential commodity of our economy and society. Meeting customer demands for greater reliability and resiliency, while providing broader and better customer services and being a good steward of the environment, all at an affordable cost, is a significant challenge. This proposed Utility 2.0 Plan was requested by New

York leaders who believe in the need for a new approach and advanced this direction through the LIPA Reform Act, and commenced a number of state-wide and local initiatives to improve service delivery for customers, transition to a more customer-centric utility business model and establish a market where third parties can provide cost effective offerings. Examples include:

- the current three year distribution rate freeze for PSEG Long Island customers;
- the implementation of recommendations from the 2013 management audit;
- the implementation of a number of operational best practices by PSEG Long Island;
- a number of efforts underway to achieve strong reliability standards and improve reliability, resiliency, storm response, and customer service;
- the update of the integrated resource plan to assess generation supply needs on Long Island;
- existing programs established by the Authority to promote energy efficiency, renewables, and demand response;
- new revenue models and requests for proposals for renewable generation that are being reviewed by the Authority with assistance from PSEG Long Island; and
- the broad-reaching Reforming the Energy Vision ("REV") proceeding recently initiated by the New York Public Service Commission ("PSC").

This proposed Utility 2.0 Plan can build upon these initiatives in several significant respects:

- <u>Accelerating and expanding investments</u> in energy efficiency and other DER to help defer or displace investments in fossil generation that may otherwise be needed in the near-term, thereby lowering emissions and customers' total bills.
- <u>Targeting opportunities to specific areas</u> to help defer or displace the need for certain investments, considering DER on equal footing (i.e., cost, reliability and local customer needs) with traditional resources.
- <u>Broadening participation to underserved customer segments</u> facing unique barriers to investing in potentially valuable energy efficient equipment and appliances. Despite the significant potential economic benefits from energy savings, some customers are unable to invest capital in new equipment. PSEG Long Island believes that reaching these customers with efficiency solutions is the next step in providing universal access to utility customers.

The support of the leadership and vision of the State of New York has been, and will continue to be, a guiding force in this process. We will continue to work collaboratively and seek to align with energy policy and initiatives supported by the Authority, the PSC, and the government of the State of New York. PSEG Long Island is an active party in the REV proceeding and intends to continue to collaborate with the Authority and New York leaders as they reconsider the responsibilities of investor-owned electric utilities and integrate DER into system operations and planning. We believe that there can be an ongoing role for the utility as the distribution system platform provider that integrates various DER options and facilitates benefits to all customers. See Section 4 for more discussion of our long-term vision for Utility 2.0.

We also believe that much can be done to develop a market of third party providers offering energy services and products to customers. Therefore, in parallel to our Utility 2.0 Plan and the ongoing REV proceeding, we will launch a process to work with leading energy service companies, demand side management companies and contractors, third party supply retailers, and other market participants to consider approaches to broaden customer energy options, incorporate cost-effective advanced technology, and further develop markets for innovative energy services on Long Island. We have already opened the dialogue with several third party providers to review the present market pricing construct and, drawing from this input, we propose investments in this Utility 2.0 Plan that can fairly and cost-effectively meet resource and customer needs. We believe that this investment program managed by PSEG Long Island will help develop markets.

As discussed further below, we will also work with communities, businesses, environmental groups, and other stakeholders to gain their input on this Plan and subsequent implementation.

1.2 Key Objectives of PSEG Long Island Utility 2.0

The following guiding principles were applied in the development of this Utility 2.0 Long Range Plan.

Integrate Utility 2.0 solutions into PSEG Long Island's long-term system and capital planning for transmission, distribution and supply.

- Resource diversity – Consider alternative design options to meet reliability and resource requirements. Evaluate distributed resources on equal footing to traditional investments, depending on their applicability, cost-effectiveness, enhanced customer services, and contribution to fulfilling State energy policy.
- Mitigate customer bill impacts – Prioritize appropriate design solutions that address reliability needs using resources with the lowest total cost. Consider total customer bill impacts in planning for both participating and nonparticipating customers.
- System modernization – Incorporate, where technologically tested, commercially reliable, and cost effective, advanced power controls for transmission and distribution facilities, technology-based energy efficiency and distributed resources, real-time power monitoring equipment, and integrated communications systems. Identify potential means to improve the efficiency of the generation portfolio on Long Island, in conjunction with our reassessment of the Authority's integrated resource plan.

Empower customers with energy choices tailored to their needs and preferences.

- Providing options – Provide information to customers regarding electricity use, usage patterns, prices, and energy reduction tools to aid in better management of energy consumption. Facilitate automated customer responses that take advantage of market signals and optimize customer preferences.
- Universal access – Enable participation in energy efficiency and other programs where "behind-the-meter" services benefit both participant and non-participant customers. Ensure universal access for new services, following a core principle in the delivery of traditional electric service.
- Customer engagement – Enhance customers' understanding of alternative design solutions to maintain reliability and system efficiency. Reach out to communities and customers for feedback in planning processes.

Enhance system efficiency and resiliency to maintain a reliable system at an affordable cost.

- Develop a cleaner and more efficient electric system – Deploy distributed resources where they are economic and where they improve the operational efficiency of the power system, particularly during peak. Increase the utilization rate of the existing delivery infrastructure and minimize the need for new generation plants to mitigate impacts on customer bills.

- Enhance reliability and resiliency – Reduce the frequency and duration of customer outages with self-healing distribution feeders, real-time monitoring and grid network controls, and other advanced technologies.

Support development of a sustainable market for clean energy investments.

- Target difficult market segments – Invest directly where market solutions do not reach certain customer segments that have difficulty participating in existing programs.
- Develop pricing framework for DER - Work with various stakeholders to develop a market for enhanced energy servies. Consider the value of these services to the utility and establish pricing approaches that providers and customers fairly.
- Create green jobs on Long Island – Enlist local workforce and contractors to implement the proposed programs.

1.3 Summary of Programs

This Utility 2.0 Plan is focused on improving energy efficiency and reducing peak load to address emerging resource and system needs across Long Island and in targeted load pockets. PSEG Long Island is prepared to invest up to $200M in these programs over a four-year period from 2015 – 2018. Our proposed investments include a mix of energy efficiency, distributed generation, renewables, and direct load control programs that are designed to result in peak demand savings to benefit the Authority and all its customers, as well as energy savings and incentives that directly benefit participants. We designed programs to encourage participation from customer segments that face barriers to existing clean energy programs, such as low income customers, public agencies, and hospitals.

We also include two capital budget investment programs for the Authority. First, we endorse a plan for the South Fork load pocket that will add distributed supply and demand-side resources. The favorable economics of these targeted improvements in the South Fork is based on the deferral of costly transmission upgrades and peaking generation. Second, we propose a targeted deployment of Advanced Metering Infrastructure (“AMI”) to large commercial and industrial customers that will enable peak demand savings through additional visibility of energy end use and enhanced metering data.

These investments are summarized in Table 1.1 below and described fully in Section 3 of the Plan. The figures are illustrative and preliminary; the actual investments could be greater or lesser than any particular program cited below and will only be made to the extent that the program satisfies the benefit-to-cost criteria described below and in more detail in Appendix A.

PSEG Long Island Utility 2.0 Long Range Plan[1]				
Program	**Description**	**Annual Demand Savings (MW)**	**Annual Energy Savings (MWh)**	**Total Investment ($M)[2]**
Programmable Thermostat Program Modernization and Expansion	Enhance existing direct load control program with modern technology and increase customer participation. Also, test smart plug technology through a pilot program targeting residential room air conditioning units.	100	2,700	$60
Targeted Solar PV Expansion	Provide incentives to commercial behind-the-meter solar PV, targeting Long Island customers unable to access existing incentives.	30	100,000	$45
Residential Home Energy Management	Provide targeted home energy reports and guidance to customers to reduce demand; 250,000 customers targeted.	10	25,000	$8
Incremental Energy Efficiency Expansion	Target additional opportunities for cost effective technology and underserved customers.	10	41,200	$30
Energy Conservation Program for Hospitals	Design and offer energy efficiency retrofit program tailored for hospital customers.	5	28,000	$30
Energy Efficiency Expansion on the Rockaways	Offer energy efficiency enhancements for low-income multi-family housing, public facilities, and other customers on the Rockaways.	5	21,500	$13
Combined Heat & Power	Provide incentives for commercial CHP installations, targeting Long Island customers unable to access existing incentives.	5	39,000	$5
Geothermal Heating and Cooling	Expand rebates for geothermal heating and cooling systems.	5	7,800	$9
	Utility 2.0 Investment	170	265,200	$200
South Fork Improvements[3]	Proceed with various energy efficiency, distributed generation, and direct load control investments, potential combined with battery storage, to defer needed transmission and peaking generation.	TBD	TBD	TBD
Large Customer Advanced Metering Initiative	Deploy advanced metering to 25,000 customers representing over 20% of the electric load on Long Island.	15	45,000	$15
	Capital Budget Investment	15	45,000	$15
	GRAND TOTAL	185	310,200	$215

Notes:
1. These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

2. PSEG Long Island proposes to finance up to $200M of the proposed Utility 2.0 Plan. This would not include the South Fork Improvements or Large Customer Advanced Metering Initiative. PSEG Long Island proposes that these two projects would be included in the capital budget.

3. South Fork will also include many other facets that are not included in the above table because they will be paid over many years from fuel and purchased power charges. Some examples include potential installation of solar PV resulting from Clean Solar Initiative II and the 280 MW Renewable RFP. Moreover, additional peaking and storage resources may be selected as a result of the Generation, Energy Storage, and Demand Response RFP. PSEG Long Island can be available as backstop developer to the extent that the competitive markets do not provide sufficient solar PV and battery resources.

Table 1.1: PSEG Long Island Utility 2.0 Long Range Plan

1.4 Benefit/Cost Test Criteria

PSEG Long Island proposes to assess the cost-effectiveness of these investments against their alternatives using the Program Administrator Cost ("PAC") test. This test considers the costs borne by the program administrator, in this case PSEG Long Island, including capital costs, administrative costs, and customer incentives. PSEG Long Island recommends that a PAC test result of 1.1 be used as the benefits-to-cost criteria

– as long as the investment's benefits-to-cost ratio meets or exceeds 1.1, it would be implemented.[2]

The PSC uses the total resource cost test ("TRC") as a cost-effectiveness metric for energy efficiency programs implemented by New York's investor owned utilities. This test is similar to the PAC test but also includes the full incremental cost of upgrading equipment. PSEG Long Island also considered the Total Resource Cost ("TRC") as a point of reference (see Appendix A).

The primary value of these investments are the avoided costs of generation capacity and energy. For our preliminary cost-effectiveness screening, we considered recent benchmark studies used by the Authority to evaluate current energy efficiency and renewable programs. The benchmark studies determined the costs of capacity and energy procured through a power purchase agreement with a new combined cycle gas turbine power plant. Such an investment represents the next real marginal unit of supply that the Authority would otherwise need. We also considered data from NYISO markets in our analysis as additional reference. In addition to the avoided cost of capacity and energy, where investments in DER can be a viable alternative to meeting reliability needs we will consider the net present value of deferring distribution investments.

More detail on the PAC test and other elements of our proposed cost-effectiveness screening is included in Appendix A.

1.5 PSEG Long Island Experience

As the Authority's Service Provider, PSEG Long Island is responsible for developing, implementing, and integrating cost-effective advanced energy investments. In this case, PSEG Long Island can apply its valuable experience implementing clean energy investments. Our utility affiliate, Public Service Electric & Gas Company ("PSE&G") has invested nearly $300 million in energy efficiency and demand response programs in just the past five years, helping reduce energy bills for a wide range of residential and commercial customers. Programs include the award-winning Hospital Efficiency and Residential Multifamily Efficiency programs, both of which provide deep energy retrofits at no upfront cost to the customer with zero-interest on-bill repayment. PSE&G has also invested approximately $700 million in securing over 150 MW of small-scale (<2

[2] The reason for using 1.1 rather than 1.0 is to account for the fact that a new supply resource would likely improve system heat rate.

MW) solar through its Solar Loan Program, which provides capital and certainty to customers deploying distributed solar, and its Solar 4 All Program, which invests in utility-owned centralized solar PV systems installed on PSE&G property and underutilized third party sites such as brownfields and landfills.

Similarly, the Authority has made significant and award-winning investments in energy efficiency, demand response and renewable energy projects through its Clean Energy Initiative, Efficiency Long Island Initiative, Solar Pioneer and Entrepreneur Program, Backyard Wind, Long Island and Eastern Long Island utility-scale solar projects, and Clean Solar, Clean Solar II and Clean Renewable feed-in tariff initiatives. PSEG Long Island has access to the same professionals that successfully implements these programs and can utilize those teams and best practices in its implementation of the Utility 2.0 Plan. See Section 2 for more extended discussion of Long Island's past and existing clean energy programs.

1.6 Investment Recovery Model

As part of this Plan, PSEG Long Island (or an affiliate) proposes to invest up to $200 million of its capital from 2015 – 2018. This investment would be incremental to the continued funding of existing energy efficiency and renewable programs. Investment by PSEG in Utility 2.0 end use measures and cost recovery are specifically contemplated by the OSA. This approach provides the Authority with low cost funding for these programs without having to further increase its debt.

PSEG Long Island proposes to align investment recovery with the upcoming Authority rate case in 2015. There will be no rate increases associated with this Utility 2.0 Plan until 2016, and we expect rate impacts to be minimal and offset by the anticipated benefits of the program, including avoided cost of alternative capacity and energy investments, and reduced peak demand and energy consumption. Any investment would be cost effective, as measured by the PAC test, and in the best economic interest of the Authority's ratepayers.

This Utility 2.0 Plan is designed to lower total customer bills from what they otherwise would have been by lowering energy usage and deferring and/or avoiding the cost of supply and system investments that would otherwise be needed. These investments will be made only if they meet or exceed cost-effectiveness criteria and lower overall system costs. PSEG Long Island also foresees that some of the rebate-focused elements of the current energy efficiency and renewable programs could be reduced as the focus shifts towards a more targeted approach with deeper retrofits and programs that better serve other customer segments, allowing for much of the program to be covered through current rates. While the investment may marginally increase customer rates after the current rate freeze, we expect total costs to be lower than they otherwise would have been.

PSEG Long Island has developed two alternative investment recovery models – both driven by customer savings – for consideration by the Authority:

1. **Performance Driven Investment Recovery Model**. In this case, PSEG Long Island proposes a performance-driven approach using our low-cost capital, with returns aligned with other New York utilities, as envisioned by the OSA. PSEG Long Island would establish a base repayment schedule based on the approved size of the program and agreed-upon rate of return. This rate could increase or decrease based upon the cost-effectiveness of the program relative to a pre-determined target, as measured by the PAC test and verified by an independent third-party. Both the increase and decrease could be capped so that the return would not exceed an agreed upon threshold. The incentive payment would be adjusted based on the level of savings achieved. Appendix B contains a draft term sheet for this proposal and illustrative repayment schedule and performance multiplier.

2. **Savings Driven Investment Recovery Model.** This case is an interim step towards valuing distributed resources more directly, an objective of the current REV proceeding. PSEG Long Island would be compensated based upon the deemed demand and energy savings of the program over the estimated life of the equipment, using the rates for avoided capacity and energy to value the investment. Deemed savings would be determined up front with verification from an independent third party. To the extent that the investment also deferred or displaced distribution investments, then that value would also be considered. Overall program returns that exceeded an agreed-upon threshold would be shared with customers, aligning incentives. Appendix C contains a draft term sheet for this proposal, proposed avoided costs from the Authority's benchmark studies, and an illustrative sharing mechanism.

In either investment recovery model, PSEG Long Island would recover its investment over an extended time frame that represents the average expected useful life of the equipment. This long-term recovery will flatten the rate impact of this acceleration of energy efficiency solutions. Long-term recovery of energy efficiency investments is a significant departure from the Authority's current treatment of energy efficiency investments, currently recovered in the same year as costs through an on-bill surcharge. The current policy may disadvantage clean energy spending that would impact annual bills disproportionally to capital investments amortized over a longer term.

In summary, PSEG Long Island's proposition to invest its own capital in Utility 2.0:

- accelerates savings from energy efficiency and peak demand reductions to help avoid other more costly investments;
- obviates the need for the Authority to expand its debt levels to finance these programs;
- spreads the costs over an extended period, reflecting the estimate useful life of the underlying equipment and thereby mitigating any rate impact;
- defers recovery until 2016, respecting the current rate freeze;
- aligns incentives for PSEG Long Island and customers around the cost-effectiveness of the programs;
- in the case of the performance driven approach, uses our low-cost capital , with returns aligned with other New York utilities, as envisioned by the OSA; and
- in the case of the savings driven approach, is an interim step towards valuing distributed resources more directly, an objective of the current REV proceeding.

In order to implement PSEG Long Island's proposed investment program, the OSA will need to be supplemented. Draft term sheets containing the principal terms and conditions for each of the proposed investment recovery models can be found at Appendix B and Appendix C of this Plan. The final term sheets will require the review of the State Comptroller, in accordance with the State Finance Law, reviewed by the DPS, and approval by the Authority's Board of Trustees.

1.7 Stakeholder Participation

We look forward to feedback from our many stakeholders on this process. As required by the OSA, PSEG Long Island will hold a public technical conference on July 24, 2014. This will be an opportunity to communicate these proposed initiatives and to receive public input. We plan to hold additional stakeholder meetings in the second half of 2014 as needed. Our community outreach will spread across Long Island, and specifically in the South Fork and Rockaway communities that we target for investment in the Plan. We intend to establish relationships with leading demand-side management providers, energy service companies, and other third-party market participants to help implement this Utility 2.0 Plan and provide insight to future Utility 2.0 plans. We will also continue to work with the Authority, the DPS, the New York State administration, and other State and local interested parties as they review this proposed Utility 2.0 Plan. See Section 5 of the Plan for further discussion.

1.8 Conclusion

This is PSEG Long Island's inaugural Utility 2.0 Long Range Plan. We believe that our proposed investments can provide a significant opportunity to meet Long Island's customer needs and policy objectives. There are many opportunities within reach and several imminent decisions regarding the long-term energy supply mix. Taking action on this Utility 2.0 Plan by the end of 2014 will enable the program to be incorporated into budgeting decisions required around the turn of the year, and projected demand savings to be incorporated into PSEG Long Island's upcoming review of the integrated resource plan. Expedited action will also provide sufficient lead time prior to the potential need for significant capacity in the summer of 2018.

This Plan will meet the initial challenge of increasing the prevalence of customer-based energy solutions in Long Island and expediting the process of integrating new distributed products and services into utility planning and business models. We believe these investments are 'no regrets' investments that can be economically favorable to their alternatives and help meet New York goals related to improving system efficiency and avoiding emissions while controlling customer costs.

Our Plan precedes the REV proceeding, but this proposal offers a natural fit and can evolve as that broader process advances. We will return each year with a report on the implementation of the Plan, including a progress report, scope refinement, and update on efforts to use this investment proposal to lead development of markets for innovative energy services on Long Island. We seek to align with both REV and related PSC proceedings, and recently proposed Federal efforts to reduce greenhouse gas emissions. We will work with New York and local leaders to refine the specifics of this proposal and develop future efforts.

In sum, we believe the proposed investments in this Utility 2.0 Long Range Plan can provide sustainable value to our customers and Long Island.

Section 2: Utility 2.0 Emerging in the Industry

2.1: Introduction

Long Island's electric grid is an interconnected network of power plants, transmission lines, substations and distribution feeders that delivers electricity to customers. While the grid continues to meet customer demand for safe, reliable, affordable electricity service, customers' expectations are changing as:

- Demand for reliability has never been greater as customers are reliant on electricity for an increasing number of everyday functions.
- Customers are becoming more comfortable with real-time information through web-based platforms and applications on smartphones and tablets.
- Technology improvements and policy support is driving interest and more opportunity for energy efficiency, demand response, and distributed generation, creating new value propositions for customers and third-party energy service providers.
- Growing concern about climate change is driving support for low or no emission generation resources and end-use efficiency.
- Strong focus on containing customer costs through greater control of energy use, and options for alternative supply and energy services.
- Ongoing utility infrastructure investment needs.

This evolving landscape requires modernization of the electric grid to meet the changing needs of customers, regulators and policy makers, and the changing nature of electric utilities. The industry has described the "Utility of the Future" or "Utility 2.0" as an evolution with a focus on grid resiliency and reliability while integrating energy efficiency, smart grid technologies, and distributed energy resources ("DER"), including demand response, distributed generation, and energy storage. Critical to the achievement of these goals is the underlying technology and market stimulating innovation in utility planning and operations. Key segments of interest to the U.S. utility industry are:

- **Energy Efficiency and Demand Side Management:** Energy efficiency programs yield both energy and demand savings, while demand response programs yield reductions in peak demand and during emergency events. Energy efficiency can permanently reduce demand and demand response typically produces peak or load reductions on an as-required basis.

High-yield energy efficiency has been realized through retrofit and replacement of lighting, heating, ventilation and air conditioning ("HVAC") systems, and other building systems. Next generation energy efficiency programs can capitalize on the untapped potential of behavioral energy efficiency, by providing customers with better access to energy use information and appliance controls communicating through web-based platforms on smart phones and tablets. McKinsey & Company estimates significant opportunity as 16-20% of residential energy use is dedicated to comfort-providing resources that could be better managed by providing information and feedback to customers, and automating appliance and building systems to accommodate customer needs and preferences.[3]

- **Distributed Generation:** Solar PV has become an increasingly prevalent source of behind-the-meter generation due to its improving costs and technical efficiency. Solar PV is also supported by various subsidies including Federal tax credits and State funding, and net metering policies. If these subsidies continue and/or technology costs decline as efficiencies improve, solar PV could become a greater part of the supply mix. Interest in other distributed generation sources fueled by natural gas, such as combined heat power systems, have renewed due to the lower costs of natural gas and the ability to maintain service during disruptions of utility service. Given Long Island's geographic constraints and relatively high retail energy costs, distributed sources can potentially be competitive.

- **Smart Grid:** Over the last few years, U.S. utilities have selectively deployed digital technology to include near-real time monitoring and controls, and smart metering infrastructure with two-way communications. This was supported by the U.S. Department of Energy ("DOE") Smart Grid Investment Grant program, which awarded a total of $4.4 billion to 100 U.S. utilities in 2009. The Authority and its partners, including the State University of New York at Farmingdale and Stoney Brook, received a grant through this program currently being implemented along the Route 110 Corridor. This DOE program allowed the awardees to implement pertinent smart grid technologies on a large scale, often for entire service areas. It also allowed U.S. electric utilities to obtain critical knowledge in the design and management of smart grid programs, and to begin realizing the potential of smart grid innovations to help utilities and customers to make better decisions on energy consumption. Smart grid solutions and advanced metering infrastructure ("AMI")

[3] "Sizing the potential of behavioral energy-efficient initiatives in the U.S. residential market" McKinsey & Company (November 2013).

hold the promise of enhanced operations, integration of distributed generation, reduced costs, and increased reliability.

2.2: New York State Clean Energy Initiatives

The New York Public Service Commission ("PSC") oversees implementation of initiatives supporting clean energy and grid modernization, and opportunities for investor-owned utilities to implement programs toward these goals.

In an order issued in April 2014, the PSC initiated the Reforming the Energy Vision ("REV") proceeding reaffirming the overarching policy objective of "reliable access to electric power at just and reasonable rates through regulatory frameworks that stimulate innovation and economic investment in an environmentally sound manner."[4] The PSC identified core policy outcomes to be achieved through a comprehensive redesign of clean energy programs, including:

- Customer knowledge and tools that support effective management of their total energy bill
- Market animation and leverage of ratepayer contributions
- System wide efficiency
- Fuel and resource diversity
- System reliability and resiliency
- Reduction of carbon emissions[5]

The REV proceeding builds on three previous PSC Orders directing reform of New York's clean energy initiatives:

- Reallocation of Renewable Portfolio Standards ("RPS") funds to support customer-sited solar PV in support of the Governor's NY-Sun Initiative. The PSC also requested that the New York State Energy Research and Development Authority ("NYSERDA") develop a process to procure solar PV in megawatt blocks with declining incentives for incremental blocks toward a program goal, and a Statewide approach coordinating NYSERDA's, the New York Power Authority's, and the Authority's programs.[6]

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[4] *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Case 14-M-0101. "Order Instituting Proceeding" (April 25, 2014).
[5] The PSC subsequently added this as a core policy objective, as recommended by DPS staff.
[6] *Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, Case 03-E-0188,* "Order Authorizing NYSERDA to Redesign of the Solar Photovoltaic Programs to a megawatt block

- Alignment of clean energy investment programs, including reform of New York's Energy Efficiency Portfolio Standard ("EEPS"). The PSC concluded that "[T]he time has arrived for a fundamental refocus of, not only the system benefit programs, but also comprehensive consideration of how our regulatory paradigm and the retail and wholesale market designs either effectuate or impede progress of our policy objectives underlying these programs."[7]
- Reallocation of clean energy program funds to the New York Green Bank, a NYSERDA-administered initiative with the goal to "help clean energy technologies gain economies of scale and attract private capital through various public/private capital arrangements."[8]

Also relevant to the Utility 2.0 Plan, in 2009, the PSC established minimum functional requirements for AMI, and later in the year DPS staff filed a proposed benefit-cost framework for AMI investments.[9] In 2011, the PSC issued a smart grid policy statement informed by comments from stakeholders and establishing several goals including enhancing reliability, controlling costs, reducing environmental impacts, empowering customers, enabling greater demand response, and accommodating new electric technologies.[10]

PSEG Long Island has considered these Orders and proceedings as guidance for development of the proposed Utility 2.0 Plan.

structure; Reallocation of Main-Tier Unencumbered Funds; and work with the Authority and NYPA" (December 19, 2013).

[7] *Proceeding on Motion of the Commission Regarding Energy Efficiency Portfolio Standard,* Case 07-M-0548, "Order Approving EEPS Program Changes" (December 26, 2013).

[8] *Petition of New York State Energy Research and Development Authority to Provide Initial Capitalization for the New York Green Bank,* Case 13-M-0412, "Order Establishing New York Green Bank and Providing Initial Capitalization" (December 19, 2013).

[9] *In the Matter of Advanced Metering Infrastructure,* Case 09-M-0074, "Advanced Metering Infrastructure, Notice Seeking Comment and Proposed Framework" (April 14, 2009).

[10] *Proceeding on Motion of the Commission Regarding Smart Grid Systems and Modernization of the Electric Grid,"* Case 10-E-0285, "Regulatory Policies Regarding Smart Grid Systems and the Modernization of the Electric Grid, Smart Grid Policy Statement" (August 19, 2011).

2.3: System Planning Goals and Emerging Resource Needs

The Authority's Electric Resource Plan 2010 – 2020 outlines emerging issues and goals that, as Service Provider, PSEG Long Island has the responsibility to review and address.[11] Some key planning issues include:

- Increased need for improved electricity system reliability and storm hardening
- Clean energy investments;
- Increasingly diversified portfolio of generation resources to maintain flexibility in meeting load;
- Supply need to satisfy Statewide Installed Capacity Requirement and Long Island Locational Capacity Requirements; and
- Modernizing the aging generation fleet on Long Island to improve generation efficiency and reduce environmental impacts of providing power to Long Island.

[11] "Long Island Power Authority Electric Resource Plan 2010 -2020" (February 2010)

2.3.1: Emerging Resource Needs

The Authority's resource needs depend on the growth and character of load on Long Island. As shown in Figure 2.1, the Authority's most recent forecast shows load growth, prior to energy efficiency and renewables, to be about 1.8% per year from 2015 – 2024. With existing programs in place to encourage energy efficiency, peak load growth is about 1.1% per year, or about 613 MW over that period. The projected peaks continue to grow despite efforts to support the general trend of improving energy efficiency and adding renewable generation capacity.

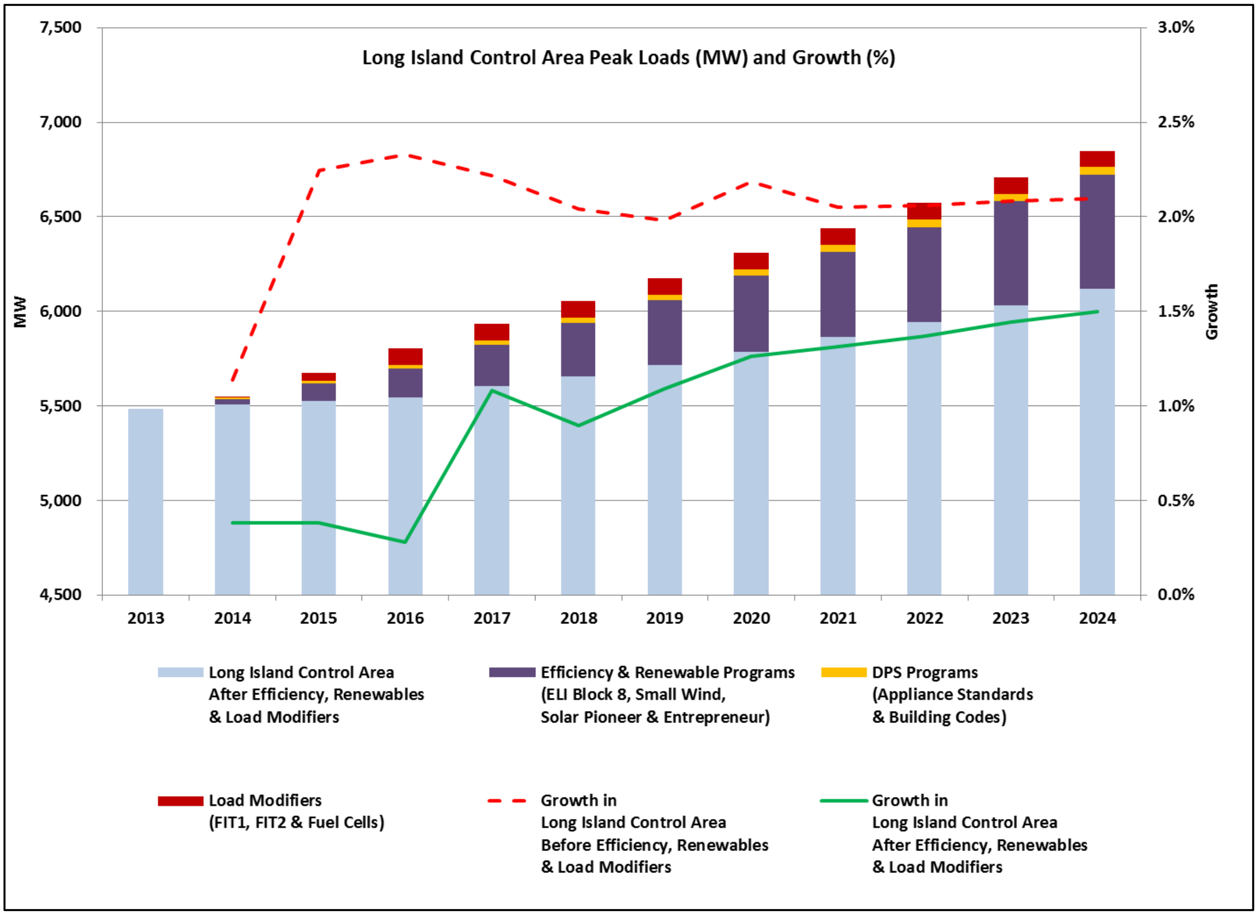

Figure 2.1: Long Island Control Area Peak Loads (MW) and Growth (%)

The peak growth is driven by residential air conditioning loads, as Long Island is a summer peaking system and residential customers represent the majority of the summer sales base. As shown in Figure 2.2, the system peaked in 2013 at 5,655 MW. Peak demand days coincided with a heat wave in July 2013, also driving peak demand in the NYISO. Approximately 1,000 MW of incremental peak load is required for less than 100 hours per year, but the system must be built to reliably meet peak demand at any time. Managing peak demand thus becomes paramount to maintaining reliable service and controlling customer costs.

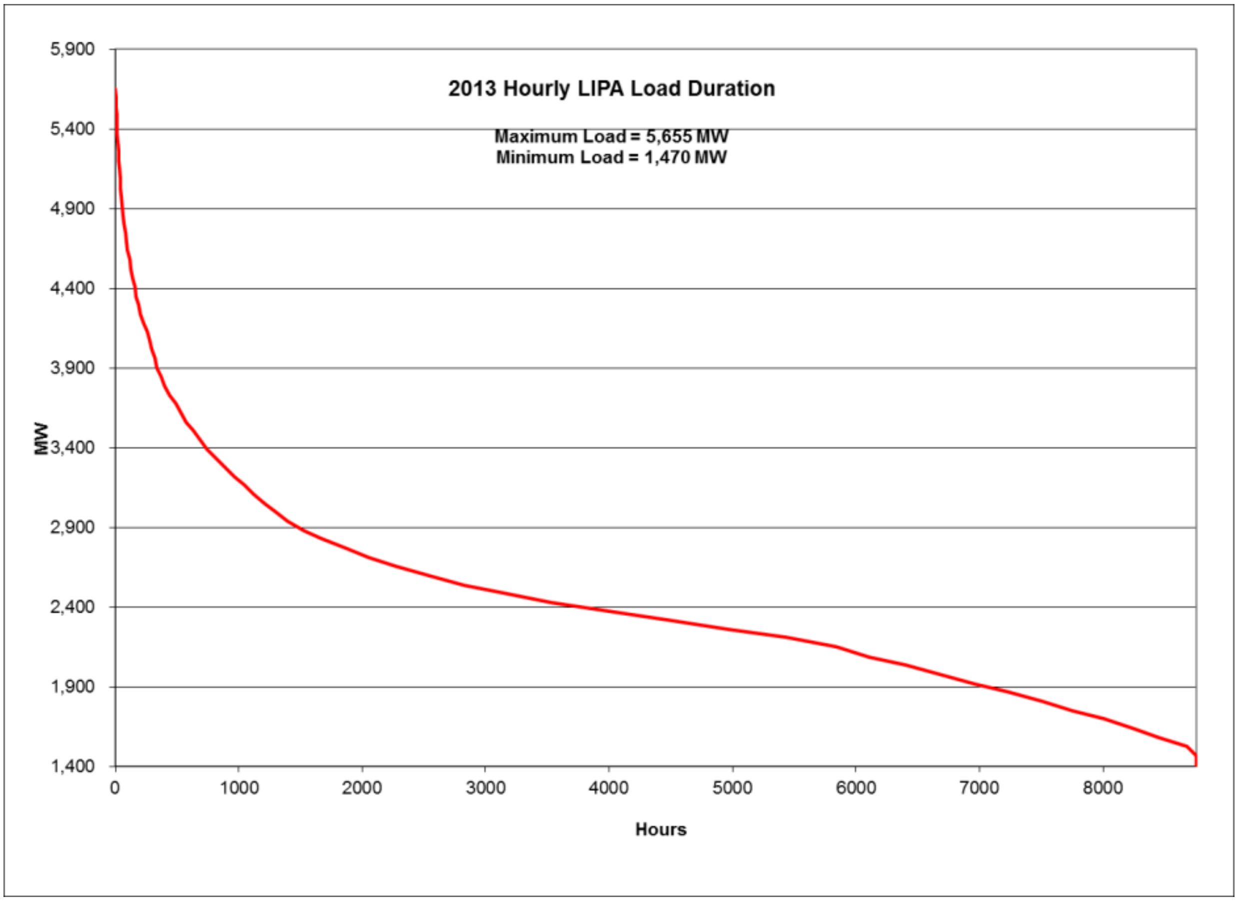

Figure 2.2: 2013 Hourly LIPA Load Duration

Since peak demand continues to grow, the Authority faces investing in assets with low utilization rates to meet peak demand. The historical trend and forecast of declining load factor, which represents the utilization of system assets, is shown in Figure 2.3. As of 2013, weather normalized system coincident load factor is down to 44.6%.[12] Over the past ten years, contributions to the system load factor have been increasing from residential and small commercial customers with below average load factors, and decreasing from larger commercial and industrial customers with higher load factors. This partly reflects Long Island's transition toward a more affluent, service oriented economy over the past ten years, as the decline in manufacturing jobs and increase in education and health services jobs has lowered the average annual energy intensity per employee.

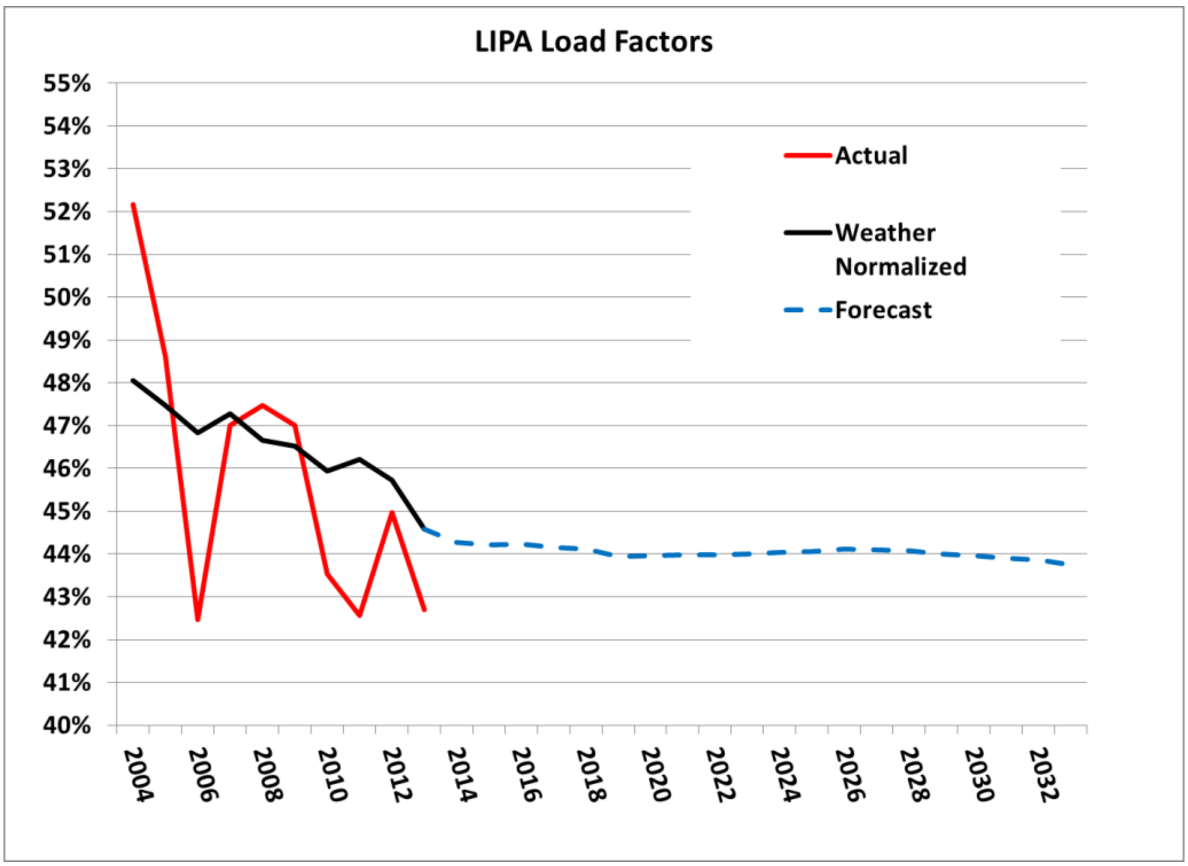

Figure 2.3: LIPA Load Factors

[12] The data reflects the Authority's Installed Capacity (ICAP) load as assigned by the NYISO, i.e., load supplied to the Authority's bundled customers and also retail access customers supplied under the Long Island Choice program. Excluded are the loads for the Authority's BNL Hydro and Recharge NY customers (less than 1% of the Authority peak load) which are supplied directly from dedicated NYPA resources under relatively recent arrangements.

The Authority has taken several measures and issued requests for proposals ("RFP") to meet supply needs emerging in 2018. The Authority has also made significant investments towards meeting its clean energy goals. Table 2.1 provides a summary of these activities, including:

- The Authority's Clean Energy Initiative ("CEI") deployed significant energy efficiency measures, as well as distributed solar and demand response, resulting in 170 MW peak load reduction. In 2009, the Authority established a new goal to meet 520 MW of emerging demand with energy efficiency investments. According to the latest report from independent evaluation contractor Opinion Dynamics these programs have resulted in 196 MW of demand reduction through 2013. Load reductions have been achieved via programs including energy efficient products, appliance exchanges, direct install of residential and commercial energy conservation measures, and efficiency ratings for new homes and other construction.
- The Authority's Solar Entrepreneur and Pioneer rebate programs have incentivized approximately 8,500 systems and 75 MW of customer-sited solar PV, representing over 1.2% of peak load. In addition, the Authority purchases the power from Brookhaven National Laboratory for the 32 MW Long Island Solar Farm, and is supporting approximately 17MW of solar PV carports in Suffolk County for the Eastern Long Island Solar Project.
- PSEG Long Island's Programmable Thermostat Program deploys direct load control demand response using smart thermostats to control central air conditioners on peak demand days to reduce peak demand on the system. The program also incorporates controllable pool pumps. The program was called on two occasions during July 2013 and achieved about 35 MW of peak demand reduction each time. Clean Solar Initiative feed-in tariff ("CSI I") offered in July 2012 was made available to solar PV systems over 100 kW (i.e. customer-sited scale) on a first come, first served basis for up to 50 MW of capacity system wide. The Authority then offered a second solicitation ("CSI II") for up to 100 MW system-wide, with individual projects not to exceed 2 MW. CSI II offered 20-year power purchase agreements to solar projects at a single clearing price, and the full 100 MW cleared the RFP process. A Clean Renewable Energy Initiative has subsequently been offered for up to 20 MW with proposals due August 29, 2014.
- A supply RFP to Provide Electric Capacity, Energy & Ancillary Services ("supply RFP") resulted in selecting the Caithness Long Island II LLC combined cycle plant in August 2013. This contract is still being negotiated.
- A recent RFP for New Generation, Energy Storage and Demand Response Resources ("GSDR") solicited supply both system-wide and in specific load pockets. Bidding closed in March 2014 and selection is targeted for 2014.

- An RFP for 280MW of New, On-Island, Renewable Capacity and Energy ("renewable supply RFP") solicited for eligible resources at a minimum 2 MW (i.e. utility scale), to support renewable energy goals in tandem with the feed-in tariff. Bidding closed in March 2014 and selection is targeted for 2014.

Resource Planning Steps Taken by The Authority			
Program	**Projects**	**Completion Date**	**Status**
Clean Energy Initiative	Commercial / Residential EE	2009	170 MW peak load reduction
Renewable Portfolio	Over 8,500 PV systems rebated. NYSERDA to provide $60M	2017	Supported 75 MW by 2013
Efficiency Long Island	Commercial - Direct Install Programs Residential - Energy Efficiency Products, Cool Homes, Residential Energy Affordability Partnership, Home Performance with ENERGY STAR®, Home Performance Direct, Residential New Homes	2018	520 MW goal 196 MW savings by 2013
Programmable Thermostat DLC Program	Controllable central air conditioning and pool pumps	2018	35MW delivered in 2013
RFP to Provide Electric Capacity, Energy & Ancillary Services	Selection of Caithness II combined cycle plant	2018	Contract under negotiation
280 MW Renewable RFP	Resources including offshore and land-based wind, solar PV, landfill gas, and fuel cells	2018	Proposals under review
RFP for New Generation, Energy Storage, and Demand Response Resources	250 MW total capacity including up to 50MW energy storage for East End 880 MW total including up to 100 MW energy storage for EF Barrett & Holtsville Up to 500 MW total, including peaking generation, energy storage, and demand response for rest of island	2019	Proposals under review
Clean Solar Initiative ("CSI")	CSI I selected 50 MW at $0.22/kWh CSI II selected 100 MW at $0.1688/kWh.	2033	50MW in progress 100MW selected

Table 2.1: PSEG Long Island Projects and Investments

2.3.2: Hardening and Resiliency Upgrades

Since 2007, the Authority has invested over $125 million in hardening its system to address major storms, hurricanes, flooding, high winds, and ice. Following Hurricane Irene and Superstorm Sandy, the Authority revisited its storm hardening policy to focus on prevention, survivability, and recovery. Storm hardening and resiliency initiatives already underway include:

- All critical transportation crossings are on target to be hardened to withstand 130 mph winds by the end of 2014.
- All ASU locations are on target to be hardened for the same wind strengths by the end of 2018.
- Flood surge zones are taken into account when designing new substations and modifying/expanding existing infrastructure.
- Since 2007, approximately 1,700 miles of distribution circuit trim is completed annually.
- Use of innovative alternatives to undergrounding transmission and distribution lines in flood and surge zones. PSEG Long Island is pursuing use of overhead distribution facilities in flood prone areas where tree coverage is limited. This eliminates risk of flooding and debris damage.
- Selected underground and pad mounted equipment in flood prone areas is being replaced with submersible equipment to protect distribution equipment from storm surge damage.
- PSEG Long Island has a pole inspection program that is evaluating poles over an 11 year period, to inspect and replace inadequate poles and equipment.
- The hardware and equipment on poor performing distribution and transmission lines are inspected and upgraded as part of Circuit Improvement Programs.
- Along the Route 110 Corridor, distribution automation systems will be used to manage the scope of outages and speed reconfiguration and restoration.
- Long term plans are under development to permanently protect substations in flood zones; in the interim, temporary trap bags or barrier systems have been installed around the perimeter of 12 substations to address the impact on equipment of substations flooded by Hurricane Sandy.

Associated with Hurricane Sandy repair efforts the Authority has also received grant of $700M from the Federal Emergency Management Agency to address hardening and resiliency. The grant will support several projects. PSEG Long Island will elevate 12 substations damaged during Sandy. The mitigation work has already started at six of the stations – Arverne, Far Rockaway, Rockaway Beach, Long Beach, Park Place and

Woodmere. Transmission lines damaged by Sandy will be strengthened to minimize the interruption of important transportation corridors due to falling conductors, and rebuild portions of damaged transmission lines. The installation of additional automatic sectionalizers will improve the resiliency of the system by reducing the number of customers impacted by a single line outage. The new devices will be intelligent devices that will be less reliant on operator interface to restore customer load. Also, mainline distribution circuits damaged during Sandy will be rebuilt with some combination of overhead and underground solutions expected to maximize the benefit of this investment.

PSEG Long Island is also currently in the process of implementing a new Outage Management System which, together with new processes, will improve storm response and outage restoration.

2.3.3: Smart Grid and Customer-Facing Technologies

The Authority has made investments in smart grid technology to improve management of the distribution system, including automated response to disturbances and outages. Since the late 1990s, the Authority installed 1,400 Automatic Sectionalizing Units that allow remote monitoring of the distribution feeder lines, quick isolation of damaged sections on the distribution lines, and the rerouting of power to undamaged lines. These measures reduce customer outage durations and system outage durations, which in turn improves reliability and customer satisfaction.

With Federal funding assistance, the Authority installed about 7,500 smart meters and related communications equipment in several pilot project demonstrations. The Route 110 Corridor Smart Grid Project included installing smart meters capable of two-way communication between the customer and PSEG Long Island. Several benefits are realized because of these smart meters such as ease of access to billing data, more granular data regarding energy usage, and improved outage information.

We have also implemented several best practices related to customer service, from basic processes that have improved the average speed of answer and lowered the call abandonment rate, to raising satisfaction from addressing customer inquiries to technological solutions, such as an Interactive Voice Response system which is being implemented this year.

2.3.4: Energy Storage and Electric Vehicles

The Authority has supported demonstrations of battery storage technology including projects at the Long Island Bus facility in Garden City, batteries associated with a photovoltaic substation on Fire Island, and a residential demonstration model in Farmingdale. In addition, there are about 1,700 electric and electric hybrid vehicles in the Authority's electric service territory.[13] The Authority was a leader in providing rebates for the purchase of electric and plug-in hybrid electric vehicles. The Authority, along with PSEG Long Island, continues to be involved in activities related to supporting the market launch of electric vehicles on Long Island, including vehicle testing programs, charging station installations, and rebate programs. Further support for energy storage technology may result from the recent GSDR, which had specific energy storage targets for the East End, EF Barrett, and Holtsville areas, as well as potential for energy storage across the system.

[13] Data provided by New York State Department of Motor Vehicles as of January 1, 2014.

Section 3: PSEG Long Island Utility 2.0 Plan

3.1: Introduction

In this Utility 2.0 Plan, PSEG Long Island proposes to invest up to $200M in energy efficiency, direct load control, distributed solar PV, and over programs a four-year period from 2015 – 2018. In addition, we include a plan for the South Fork load pocket that will add distributed supply and demand-side resources. We also include a targeted deployment of AMI. In all of these investments, the focus is on improving energy efficiency and reducing peak load, as well as increasing participation from distributed resources.

Please note that the savings and investments described in this section are preliminary. We provide program sizing estimates based on PSEG Long Island and PSE&G experience with clean energy programs, load research and other internal data, and knowledge gained through interviews and information requests from vendors and potential program partners. Our estimates represent illustrative target savings that will deviate based on DPS review and Authority approval of different components of the Utility Plan. Actual costs may vary based on subsequent competitive bidding process to procure implementation program managers, equipment vendors, and contractors.

PSEG Long Island proposes to assess the cost-effectiveness of these investments against their alternatives using the Program Administrator Cost (“PAC”) test. This test considers the costs borne by the program administrator, in this case PSEG Long Island, including capital costs, administrative costs, and customer incentives. PSEG Long Island recommends that a PAC test result of 1.1 be used as the benefits-to-cost criteria – as long as the investment’s benefits-to-cost ratio meets or exceeds 1.1 it would be implemented.[14]

The PSC uses the total resource cost test (“TRC”) as a cost-effectiveness metric for energy efficiency programs implemented by New York’s investor owned utilities. While PSEG Long Island has considered the TRC test (see Appendix A), we favor using the PAC test for this Plan for several reasons:

[14] The reason for using 1.1 rather than 1.0 is to account for the fact that a new supply resource would likely improve system heat rate.

- With the PAC test, the rebate is set at a level that is cost-effective for PSEG Long Island and the customer can decide whether or not to pay the incremental cost.

- The PAC test implicitly accounts for externalities because customers' willingness to pay is proportional to their perceived overall benefit, including environmental benefit, customer comfort, and customer convenience. While the TRC can be modified to include externalities, it can be difficult to quantify those benefits.

- The PAC test can limit rate impacts because it provides an incentive to achieve the same results with lower costs. The TRC considers customer incentives a pass-through cost with no effect on the benefits-to-cost ratio.

- All costs in the PAC test flow through electric rates. The test is analogous to supply-side resource acquisition where all costs flow through rates to customers. Our proposal to amortize costs over the expected life of equipment (i.e. eight to twelve years) would bring supply and demand side resources even closer into alignment.

PSEG Long Island estimated the benefits of Utility 2.0 as the net present value of the avoided capacity and energy costs resulting from the measure or program undertaken. The avoided costs were developed in a benchmark study blending four proposals for combined-cycle gas turbine generating units received in response to the Authority's supply RFP in 2011. The values were updated in January 2013 with more recent bid evaluation information and natural gas prices. The benchmark study has been used by the Authority to screen the existing energy efficiency and renewable energy program portfolio.

More detail on the PAC test and other elements of our proposed cost-effectiveness screening is included in Appendix A.

3.2 Utility 2.0 Investments

PSEG Long Island has developed a number of programs focused on providing immediate benefits of peak demand savings, as well as energy savings and other cost savings. PSEG Long Island or an affiliate is prepared to finance up to $200M of these Utility 2.0 investments through supplements to its existing OSA with the Authority.

3.2.1 Programmable Thermostat Program Modernization and Expansion

Background

Direct Load Control ("DLC") programs demonstrate significant benefits such as peak load reductions, optimization of generation resources, and increased asset utilization. The ability to cycle participant equipment permits the utility to call on DLC resources more often than interruptible resources and provides improved load management capabilities during extreme peak loads and emergencies.

PSEG Long Island's Programmable Thermostat Program provides participants with a controllable thermostat and uses a one-way pager signal to remotely cycle (i.e., switch off) air conditioning units and pool pumps. The DLC program originated in 2001 and achieved 35 MW peak demand reduction in 2013.

PSEG Long Island Programmable Thermostat Program			
Customer Segment	Total Customers	DLC Participants	Participation Rate
Residential with CAC	400,000	21,969	5.4%
Small C&I (<100kW)	100,000	6,265	6.3%
Residential with pool pumps	150,000	1,468	1.0%

Table 3.1: PSEG Long Island Programmable Thermostat Program

Note: Based upon a 2011 Long Island population survey, we conclude that there are 40% (400,000) customers with Central Air Conditioning ("CAC") units and more than 500,000 customers with one or more room air conditioners. [15] Also, we believe there are 150,000 pool pumps on Long Island based on our prior experience with DLC.

However, the 35MW delivered in 2013 may not be available going forward. The equipment used in the DLC program has exceeded its useful life and has begun to experience a higher failure rate. Equipment will need to be replaced in the near term to ensure that the load reductions are achieved, and some innovations to consider include:

- New thermostat technologies coupled with two-way communications provide better control and monitoring of DLC programs to the utilities. The technology is readily available from several vendors and can be integrated with customers' wireless-enabled smart phones and tablets.
- When the Authority's original DLC program was implemented, the market offered DLC hardware only, and the Authority was responsible for equipment installation, program marketing, analysis of results, and customer service. Several different options now exist to engage one turn-key contractor to provide all equipment and services in one bundled package.
- In the past, DLC programs and their communications networks were vendor proprietary and hence more costly. OPENADR protocol, implemented in the last five years, ensures uniform communication protocol for all DLC devices. This inter-operability requirement, capable of integrating multiple devices and communications systems from different vendors, promotes innovations and competition.
- Using two-way communication systems, it is now widespread to have verifiable measurements at aggregate levels as well as at customer levels.

PSEG Long Island Proposal

PSEG Long Island proposes to modernize and expand the Programmable Thermostat Program to provide up to 100 MW of peak demand reduction to the Authority, including retaining the existing 35 MW demonstrated in 2013 and adding an incremental 65 MW to the program. Legacy participants would receive replacement thermostat equipment to enhance tracking participation and results validation. We also plan to work with leading DLC program vendors and develop an RFP to add central air conditioning and pool pump participants to the program. We intend to allow customer incentives to encourage participation and recognize the value of this distributed resource. We target

[15] 2011 Long Island Population Survey – the Authority. http://www.lipower.org/pdfs/company/pubs/popsurvey/popsurvey11.pdf

activating the program for approximately 27 to 45 hours annually (i.e., 6 to 11 days, for an average of 4 hours a day).

As a related pilot program, PSEG Long Island proposes to test “smart plugs” capable of monitoring and controlling plug-in appliances, with a focus on capability to cycle room AC units for peak reduction and overall energy savings. Smart plugs control demand, monitor energy use, and allow a utility or third party aggregator control center to measure and verify energy consumption reduction. The technology can facilitate expanded participation by customer segments that rely on room AC units (e.g., apartment dwellings). Considering that this is an evolving technology, we propose a limited pilot to prove the technology potential.

In addition to enrolling customers across the service area, PSEG Long Island would seek to target DLC where incremental load relief would defer costly distribution projects. This would represent additional benefits of the program. Conceptually, we could deploy DLC where load reduction, peak load characteristics, number of times DLC measures will be needed annually, and likely reliability impact and duration of the deferment provide sufficient capability. This concept would be a step to directly integrate distributed resources into our system planning responsibilities.

<u>Illustrative Market & Results</u>

PSEG Long Island envisions enrollment in end use measures similar to the existing DLC program:

- *Central Air Conditioning*
  PSEG Long Island would enroll residential and small business controllable central air conditioning (“CAC”) systems, as it currently does, with advanced thermostat equipment. We expect an average 1.1 kW load reduction for residential customers, based on a recent survey of 23 utility DLC programs with residential and small business customers.[16] This figure is also consistent with our existing residential customer performance, though our small business customers exhibit a slightly higher load reduction of 1.3 kW.

  To reach the goals of the Utility 2.0 Plan, PSEG Long Island will have to improve from its current 4% participation rate in its DLC program. For comparison, the same utility survey found DLC program participation rates ranging from 5% to 40%**,** with 10% to 15% participation rates for utilities similar in size to PSEG Long Island.

[16] ”Hot or Not: DLC Program Benchmarks” E-Source. Spring 2012.

A recent survey conducted by ORC International in New Jersey for 450 residential customers concluded that 13% customer enrollment rate is achievable when the program offers a one-time incentive of $50, and the rate will increase to 19% if $100 is offered.[17]

Based on this analysis, PSEG Long Island will assume 11% - 15% participation rate of residential CAC. For small business CAC, we assume 8% - 10% participation rate, which represents a slight improvement over current participation of that segment.

- *Pool Pumps*
  There are approximately 150,000 pools on Long Island and 1,500 pools, or 1%, participate in our DLC program. Because controllable pool pumps do not impact customer comfort, we believe higher participation is achievable and assume a high participation rate of 20% participation, or 30,000 pools.

- *Smart Plug Room AC Units*
  PSEG Long Island also proposes a pilot program deploying smart plug technology for residential room AC units. Smart Plugs are devices that consumers can plug into electric outlets, and then plug their appliances into, in order to receive device-level power measurement and enable programmable energy use of plug-in appliances. Users can take advantage of data collected by smart plugs to actively manage their energy use and participate in demand response and DLC programs. Our goal will be to deploy 1,000 smart plugs and monitor energy reductions to determine future potential of this technology.

The exact size of the program will be based upon the cost of equipment, customer incentives, participation rates, and other factors. These will be better understood through an RFP for the program, but below are our target load reduction goals.

[17] "Cool Customer Program Response – Final Report." ORC International. March 2013.

Programmable Thermostat Program Modernization & Expansion Illustrative Summary				
MW Target	Technology	Metrics	Customers	Participation Rate**
70 MW	Residential CAC	1.1kW/customer	60,000	15%
10MW	Small Business CAC	1.3kW/customer	8,000	8%
20MW	Pool Pumps	0.678kW/pool	30,000	20%
N/A	Smart Plug*	0.2kW/customer	1,000	N/A
Total Savings: 100 MW / 2,700 MWh		Total Cost: $60M		PAC B/C Ratio: 3.7

*These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

**This rate is the targeted participation rate of the customers who are eligible rather than total residential customers. For example, residential customer CAC would target the 400,000 customers with CAC, and for the minimum 70 MW load reduction we would need approximately 15% of these customers to participate.

Table 3.2: Programmable Thermostat Program Modernization & Expansion – Illustrative Summary

Next Steps

- Obtain approvals for DLC program modernization and expansion
- Collect market intelligence and capabilities from DLC vendors
- Develop scope and timeline for DLC program
- Incorporate distribution system planning needs for specific load centers, as feasible
- Issue RFP for vendor and program support

3.2.2: Targeted Solar PV Expansion

Background

The Authority has historically incentivized the deployment of solar PV and renewable energy projects through a variety of programs including the Clean Solar Initiatives ("CSI " and "CSI II"), the Clean Renewable Energy Initiative, support for utility-scale solar projects, the 280MW renewable supply RFP, the Solar Pioneer and Entrepreneur Programs, the Backyard Wind program, and the Solar Thermal program. PSEG Long Island believes potential remains to support behind-the-meter solar PV projects hosted by commercial customers.

PSEG Long Island Proposal

PSEG Long Island proposes a program targeting behind-the-meter solar PV projects greater than 200kW, but less than 2,000 kW. Solar PV projects within this size range and located in NYISO's Zone K are not currently eligible for incentives offered by the New York State Energy Research & Development Authority ("NYSERDA"), or the Authority. We envision an incentive design similar to the NYSERDA NY-Sun Competitive PV Program. Successful applicants would receive an up-front payment along with two performance payments in order to encourage the installation of high performing systems. Qualified applicants would be competitively selected based on the incentive bid received. PSEG Long Island customers could participate in the program directly or serve as hosts for project owners.

We also propose tailoring these incentives to system planning needs. We would also consider providing a premium value for peak capacity. As discussed in our Rockaways proposal, we could include a premium incentive to west-facing projects that provide high capacity value coincident with peak demand.

Illustrative Market & Results

PSEG Long Island is in a position to build on the solar PV incentives established by the Authority. The application submittal period for CSI II closed January 31, 2014, and the offering was significantly oversubscribed, with over 227MW of capacity responding to the call for 100MW. Many of the unsuccessful applicants could potentially reconfigure their projects to interconnect behind the meter and participate in the proposed program. However, successful applicants to either CSI would not be permitted to participate in the proposed program. Customer-sited solar projects would benefit from the proposed incentive from PSEG Long Island coupled with Federal incentives and net-metering. All of these benefits would improve the economics and success rate of customer-sited solar projects.

We believe our program could support 60 MW_{DC} of nameplate capacity by 2017, equating to approximately 30 MW_{AC} of peak demand due to the mismatch between peak solar output mid-day and peak demand later in the afternoon.

Targeted Solar PV Expansion Illustrative Summary		
Total Savings: 30MW / 100,000 MWh	Total Cost: $45M	PAC B/C Ratio: 3.9

*These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

Table 3.3: Targeted Solar PV Expansion – Illustrative Summary

Next Steps

- Obtain approval for Solar PV Expansion
- Collect market intelligence and capabilities from solar vendors
- Solicit for specific project proposals including siting and sizing

3.2.3 Residential Home Energy Management

Background

Behavioral energy efficiency is an extension of customer education and outreach programs. Behavioral programs combine the insights of behavioral science and consumer marketing with advanced technologies to change energy end use patterns and encourage purchases of energy efficiency products and services.[18] Peer comparison feedback drives the reduction in energy usage. Typically, participants receive regular reports of their energy consumption along with a usage benchmark based on attributes that may include home square footage and type of appliances and equipment in the home. Participants also typically receive suggestions for managing energy end use, and may be directed to value-added services or other energy efficiency offerings.

Many utilities have implemented behavioral science energy efficiency programs in the last decade. The traditional approach has included a pilot program of several thousand customers, followed in many cases by expanded offerings. Below is a summary of some examples:

18 "Residential Energy Efficiency: It's the Behavior, Stupid". Energy Central. May 11, 2009.

- A 2009 study conducted by Yale Law School examined large-scale applications of behavioral energy efficiency. Customers were provided feedback and peer comparison data. The study noted resulting reductions in energy consumption of 2.0% at Sacramento Municipal Utility District and 1.2% at Puget Sound Energy.[19]

- An initial study of PPL Electric's residential customer behavior-based program indicated that the average peak demand savings were about 0.07 kW per home, for a total peak reduction of about 6.5 MW.[20] PPL sent home energy reports to approximately 100,000 residential customers with above-average electricity use between June 2010 and May 2013. The reports encouraged customers to adopt energy savings measures, many of which would also reduce the utility's system peak. Hourly energy-use data were collected between June and September 2012 for a sample of these participating customers and a control group.

- A recent evaluation of National Grid's Residential Building Practices and Demonstration Program, approved by the PSC in 2010, found 2.3% energy savings as a result of providing customers home energy reports, peer comparisons, and ideas on energy efficiency, from May 2011 to December 2012.[21] The evaluated savings were significantly higher than expected.

- Central Hudson's Home Energy Reporting Program was also approved by the PSC in December 2010.[22] The program tested the effectiveness of home energy reporting for 100,000 customers over a 15-month period. Enrolled customers received information about their energy use and education about low-cost measures, practices, or behaviors to reduce end use.

- Baltimore Gas & Electric ("BGE") launched a Behavioral Demand Response program in summer of 2013 to 300,000 residential customers, sending millions of

19 Prof. Ian Ayers et al. "Evidence from Two Large Field Experiments that Peer Comparison Feedback Can Reduce Residential Energy Usage". July 16, 2009.
20 "Are You Leaving Peak Demand Savings on the Table? Estimates of Peak-Coincident Demand Savings from PPL Electric's Residential Behavior-Based Program". Working Paper. James Stewart and Pete Cleff. November 18, 2013.
21 "National Grid Residential Building Practices and Demonstration Program Evaluation". DMV KEMA Energy and Sustainability. January 15, 2014. (submitted to DPS in Case 07-M-0548)
22 *Proceeding on Motion of the Commission Regarding Energy Efficiency Portfolio Standard,* Case 07-M-0548, "Order on Rehearing Granting Petition for Rehearing" (December 3, 2010)

personalized multi-channel messages to customers before and after peak events. BGE plans to expand this program to all 1.1M electricity customers by 2015. [23]

PSEG Long Island Proposal

PSEG Long Island proposes a behavioral energy efficiency program that would deploy an energy information platform to residential customers. The program would be a first step on Long Island to empowering mass market customers to manage their energy use by enhancing visibility of energy consumption data and peer benchmarks. There are a variety of approaches that leverage behavior, but best practice combines the following elements:

- **Personalized Information.** Providing customer bill information, including an analysis of the home's energy use during the previous 24 months and analysis of energy use in the current year compared to the previous year. Hardware, software, and in-home energy audits can communicate actionable information to the consumer.
- **Social Pressure.** Comparison of the home's energy use with approximately 100 similar neighbors. This information provides customers with a benchmark point of reference to consider when optimizing their energy use.
- **Contextual Feedback.** Bi-monthly reporting including bill analysis and other forms of feedback to influence household energy behavior. A typical report provides easy-to-interpret graphics and charts that show customer's energy usage, comparison to similar customers, and suggestions to lower energy consumption. The program can utilize a variety of technology and communications strategies, providing customers with online access to energy reports also accessible via smart phones and tablets. Suggested action steps and custom tips for reducing energy use will be provided, as well as marketing for PSEG Long Island energy efficiency and demand reduction programs.

PSEG Long Island proposes to send six bi-monthly reports to its select customers to enhance the visibility of their consumption data and improve management of their energy use.

[23] "A web-based dialogue on the power of engaging customers to save money while managing peak demand." Ruth Kiselewich, Director, DSM Programs at BGE. Found at http://www.peakload.org/?page=DRDialogueBGE

Illustrative Market & Results

We propose to offer this program to select residential customers based upon certain pre-screening criteria. We will work with a competitively-selected program implementation provider to determine customer eligibility criteria, which may include:

- **Above-average energy use.** A threshold of 10,000 kWh/year can identify customers with higher potential for energy efficiency and peak demand reductions.
- **Geographic locations.** Customers in areas identified by PSEG Long Island as exhibiting demonstrated needs to reduce peak loads.
- **Existing or planned smart meters.** Smart meters would provide hourly data and measurement and verification of results.
- **Billing history.** Customers with billing history at the same address for the previous 12 months exhibit stability in data collection.

Most behavioral energy efficiency programs value their savings by benefit to customers of avoided energy costs. Independent third party evaluations have typically determined energy savings of 0.5% - 2%. For our illustrative market sizing, we target 0.5% energy savings. Using PPL's program as a guide, we assumed that a goal of 0.04kW demand savings per targeted customer is reasonable.[24] We would phase in participation annually to reach a cumulative total of 250,000 residential customers enrolled in the program.

[24] We consulted with a behavioral DR vendor that validated this assumption.

Residential Home Energy Management Illustrative Summary			
Year	**Cumulative Number of Customers****	**Demand Savings**	**Energy Savings**
2015	50,000*** (2 reports each)	0	0
2016	150,000 (6 reports each)	6 MW	15,000 MWh
2017	250,000 (6 reports each)	10 MW	25,000 MWh
2018	250,000 (6 reports each)	10 MW	25,000 MWh
Total	**250,000 customers**	**10 MW**	**25,000 MWh**
Total Savings: 10MW / 25,000 MWh		Total Cost: $8M	PAC B/C Ratio: 1.3

*These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

**These are total cumulative customers in the program in the stated year.

*** Assuming approval to begin at the beginning of 2015, and considering time for solicitation of proposals and start-up, these customers would be enrolled by end of 2015. There would be no savings in 2015.

Table 3.4: Behavioral Energy Efficiency Programs

Next Steps

- Approval of home energy management program
- RFP and vendor selection
- Vendor software integration with PSEG Long Island customer information systems
- Targeted customer selection, in consultation with selected vendor
- Design specific messages and finalize messaging
- Benefit measurement and validation of program success

3.2.4 Incremental Energy Efficiency Expansion

Background

PSEG Long Island manages and implements the Authority’s existing energy efficiency programs, targeting 520 MW demand savings and a ten-year investment of $917 million from 2009 – 2018. These programs have resulted in energy and capacity savings of about 1.0% demand and 1.3% energy savings annually.

Historic Energy Efficiency Savings						
	Residential		Commercial / Industrial		Totals	
Year	MW	MWh	MW	MWh	MW	MWh
2010	17.0	95,156	10.6	47,580	27.6	142,736
2011	17.6	100,078	16.5	70,809	34.1	170,887
2012	23.3	128,110	28.0	116,046	51.3	244,156
2013	28.7	159,295	28.7	116,260	57.4	275,555
Totals	86.6	482,639	83.8	350,695	170.4	833,334

Table 3.5: Savings achieved by LIPA and PSEG Long Island Energy Efficiency Programs

However, energy efficiency programs in Massachusetts, Arizona, Rhode Island, and Vermont currently expect 2% demand reductions, and Illinois, Maryland, Maine, Minnesota, Colorado and Indiana expect to exceed 1.5% demand reductions.[25] Higher level of savings may be achievable on Long Island given that energy efficiency is not close to reaching saturation in terms of 2012 technologies, and new technologies are already making 2012 technologies obsolescent.

PSEG Long Island Proposal

We propose to develop an energy efficiency program that will result in savings incremental to the existing offerings available on Long Island. Incremental savings can be achieved by a combination of increased incentives for measures that produce large demand savings, designing programs to increase participation by traditionally underserved customers, and aggressive marketing.

We anticipate developing deep retrofit projects with energy conservation measures identified by investment grade audits, such as HVAC unit and lighting replacement to bring to current efficiency standards. The program could also include appliance recycling and direct install projects focused on peak demand savings. For example, we envision a targeted program exchanging efficient room AC units (equipped with technology to enable direct load control), refrigerators, and dehumidifiers that meet our cost effectiveness test thresholds.

[25] "Change is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution," ACEEE Report E1401, April 2014.

Estimated Market & Results

Our target customer segments may include multi-family buildings, including government housing authorities. Long Island communities support government-assisted housing authorities in Hempstead, Long Beach, North Hempstead, and Oyster Bay, for a total load of approximately 5 MW. There are another 25 multi-family residential developments with approximately 11.5 MW of load. PSEG Long Island would explore potential to improve 90 nursing home facilities across Long Island, including 28 homes with average loads in excess of 200 kW representing approximately 5.6 MW of total loads. Based on these data points, we believe approximately 10 MW of savings is a reasonable goal.

Incremental Energy Efficiency Illustrative Summary		
Total Savings: 10 MW / 41,200 MWh	Total Cost: $30M	PAC B/C Ratio: 1.6

*These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

Table 3.6: Incremental Energy Efficiency – Illustrative Summary

Next Steps:

- Obtain approval to pursue incremental energy efficiency opportunities
- Develop new or modified programs targeted for specific customer segments
- Develop outreach and marketing plans with the customers and contractor base
- Actively market the program
- Regularly monitor the progress and develop corrective action plans

3.2.5 Energy Conservation Program for Hospitals

Background

One of PSEG Long Island's central Utility 2.0 principles is maintaining universal access, but certain Long Island customers are unable to participate in clean energy programs. Hospitals are one such underserved customer segment. Hospitals are critical facilities that provide a valuable service to the public, and energy savings from any programs would indirectly benefit the public through lower costs. But hospital customers find it difficult raising capital to finance the upfront costs of clean energy investments, regardless of cost-effectiveness and energy saving potential, preventing them from improving efficiency.

PSEG Long Island Proposal

PSEG Long Island proposes an energy efficiency program designed to reach out to hospital customers with peak load greater than 1 MW. Typically, these large customers have participated in existing programs to improve lighting, and represent further potential for demand savings through deep retrofit of energy-intensive equipment.

The program would be designed consistent with an existing program successfully implemented by our New Jersey utility affiliate, Public Service Electric & Gas ("PSE&G"), since 2008. The PSE&G program invests in upgrades at New Jersey hospitals resulting in peak load reduction, energy savings, and lower energy bills for its participants. Eligible hospitals receive a free investment grade audit ("IGA") of their facilities. The Program is limited to in-patient hospitals and other in-patient medical facilities that operate twenty-four hours a day, seven days a week. PSE&G and an engineering contractor review the IGA with the customer to identify cost effective energy conservation measures that may include lighting, HVAC, humidification, ventilation, motors, energy management systems, and other energy consuming equipment. All energy conservation measures identified by the IGA as having a simple payback of 15 years or less are considered eligible investments. The customer is responsible for soliciting and selecting an installation contractor, and managing implementation. PSE&G covers the upfront costs of the project and the customer repays their cost share, interest free, through on-bill financing. These costs are at least offset by the energy savings.

Illustrative Market & Results

PSEG Long Island has 10 hospitals with peak load higher than 1 MW for a total load of 83 MW. Several of these hospitals have utilized the existing energy efficiency rebate programs on Long Island to finance lighting upgrades. In recent discussions with some hospital customers, which will remain anonymous, we determined the following:

PSEG Long Island Hospital Customers' Observations	
Hospital No. 1	Goal to reduce annual energy budget through aggressive energy conservation plans
Hospital No. 2	Economic issues have prevented it from replacing old equipment
Hospital No. 3	Looking to replace chiller in next year or two
Hospital No. 4	Exploring the need for new chillers
Hospital No. 5	Very focused on energy efficiency certification and would benefit from deep retrofit
Hospital No. 6	Exploring the need for replacement chillers

Table 3.7: PSEG Long Island Hospital Customers' Observations

Based on our experience in New Jersey and our knowledge of hospital customers on Long Island, PSEG Long Island assumes a 50% participation rate and 10% peak load reductions as a result of this program. Though the actual savings are dependent on the level of participation and the economics of each individual project, we assume at least 5 MW of demand savings is achievable through this program.

Hospital Outreach Program Illustrative Summary		
Total Savings: 5 MW / 28,000 MWh	Total Cost: $30M	PAC B/C Ratio: 1.2

*These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

Table 3.8: Hospital Outreach Program – Illustrative Summary

Next Steps

- Obtain approval for Hospital program
- Develop customer outreach and marketing plans with the customers and contractor base
- Establish audit IGA Framework and PSEG Long Island review framework
- Actively market the program using PSEG Long Island large customer management staff
- Regularly monitor the hospital installation applications and progress, develop corrective action plans if the installation progress is below the annual targets

3.2.6 Energy Efficiency Expansion on the Rockaways

Background

The Rockaways include residential neighborhoods, public services (e.g. hospitals, wastewater treatment plants), and a cluster of six New York City Housing Authority ("NYCHA") public housing developments. Superstorm Sandy devastated parts of the Rockaways, particularly Rockaway West and Breezy Point. New York City and New York State have planned disaster recovery support for the neighborhoods. PSEG Long Island recognizes the need for targeted investment in rebuilding these communities stronger and smarter than before. Since the Rockaways have limited generation and transmission interconnections, distributed energy resources may have significant benefits to customers in this region.

PSEG Long Island Proposal

PSEG Long Island proposes a targeted investment program in load reduction for the Rockaways. Our program includes energy efficiency modernization and solar PV installation, both of which may aid Rockaway customers in managing their electricity bills. The Rockaways have a significantly higher percentage of customers unable to utilize PSEG Long Island energy efficiency and renewable programs. By offering targeted investment programs to these customers, PSEG Long Island can foster universal access to clean energy programs. The load reduction also has potential to improve PSEG Long Island's readiness to meet distribution system reliability criteria for the Rockaways.

Our program approach includes an appliance replacement program in which participants would receive replacements of lighting and eligible energy efficient appliances including room AC units and refrigerators. New appliances would be Energy

Star certified to adhere to modern efficiency standards. Outdated models would be collected to ensure the program results in energy savings rather than additions.

Another component would be a direct install program to commercial customers, with a focus on lighting for relatively low cost, high impact savings. Commercial customers would be eligible for a free investment grade audit of their facility, review of potential energy conservation measures, and project management assistance. The program can leverage the existing Small Business Direct Install Program and target Rockaway commercial customers.

We also propose to include solar PV as part of a targeted program in the Rockaways. Despite prior incentive programs, only nominal amounts of solar have been installed on the Rockaway peninsula. PSEG Long Island proposes incentives for solar PV projects located in this region consisting of systems greater than 200 kW, but less than 1,000 kW. We would also consider providing a premium value for peak capacity by incenting west-facing solar, which has higher production later in the day, coincident with peak demand.[26]

Participants can benefit from this incentive along with the Federal Business Energy Investment Tax Credit ("ITC") eligible for solar systems placed in service before December 31, 2016. Qualified applicants would be competitively selected based on their incentive bid in dollars per kilowatt hour ($/kWh) payable in periodic installments. PSEG Long Island electric customers may participate in the program directly or serve as hosts for project owners. Local municipal entities could potentially benefit from electricity savings by partnering with power purchase agreement providers able to efficiently monetize the Federal ITC.

Illustrative Market & Results

While we propose that our program be open to all PSEG Long Island electric customers in the Rockaways, we have also discussed establishing public-private partnerships with NYCHA and the New York City Department of Citywide Administrative Services ("DCAS"). Both have a number of facilities and significant load in the Rockaways, and share similar clean energy goals with the Authority. Based on preliminary analysis we have developed the following illustrative plan:

[26] "Installed Capacity Manual." New York Independent System Operator. May 2014.

- *Room AC*
  NYCHA has approximately 4,000 housing units in the Rockaways and there are over 3,000 room AC units registered by residents. The majority of these AC units are likely older and inefficient models. Working with NYCHA, we could replace each unit with a more efficient model. We expect to replace all of the registered NYCHA units, plus some unregistered units. In addition, DCAS conducted a facility survey estimating over 500 room AC units at schools, administrative buildings, and other facilities. Likely, many are eligible for replacement. Our program would also be open to Rockaways residential customers with room AC units – we expect there is significant potential from multiple large multi-family housing buildings in the Rockaways.

  Additionally, PSEG Long Island would require that new room AC units come equipped to participate in our proposed DLC smart plug pilot, as described above. Customers could receive the option to provide PSEG Long Island direct load control capability.

- *Refrigerators*
  NYCHA has over 6,000 refrigerator units registered at its developments in the Rockaways. While the age of individual units is unknown, NYCHA's records indicate that the last major replacement took place in the late 1990s. PSEG Long Island would consider opening this program to other residential customers in the Rockaways to the extent replacing their appliances would result in cost-effective savings.

- *Residential Lighting*
  PSEG Long Island and NYCHA could market and implement a light bulb exchange program, as well as a direct install program for lighting within residencies and building common areas. Residents would exchange incandescent bulbs for more efficient products. The program may also be successful at other multi-family housing buildings in the Rockaways.

- *Commercial Lighting*
  Several customers have taken advantage of the existing Small Business Direct Install program offered, leading to approximately 1% energy savings via 3% small business customer participation. We would extend this direct install lighting program to small business customers in the Rockaways as a complement to existing energy efficiency programs. This commercial lighting program would target customer facilities to accelerate meeting the remaining potential in the Rockaways. DCAS may be a partner in this program. Based on preliminary

discussions, DCAS facilities could support commercial lighting retrofit potential in schools and other government buildings if we are able to meet their needs.

- *Solar*
  Sizing for the solar component of this program ultimately depends on response to a competitive solicitation, but we estimate that our program would support 2 MW of nameplate capacity, or 1 MW of peak demand. At this time, PSEG Long Island has at least 25 commercial electric customers located in the Rockaway peninsula with a peak demand in excess of 200 kW. In addition, DCAS recently conducted a technical review of their properties and determined that they could collectively host in excess of 2 MW.

The market potential and costs of our Rockaways program are subject to change, but based on discussions with NYCHA and DCAS, as well as internal analysis of the load in the area, we have developed the potential below:

Energy Efficiency Expansion on the Rockaways Illustrative Summary			
MW Target	Customer Types	Metrics	Targeted count
1.5	Room A/C Replacement	0.2kW/customer	7,500
0.5	Refrigerators	0.9kW/customer	6,000
1.0	Residential Lighting	0.1 kW/customer	10,000
1.5	Commercial Lighting	1kW/customer	1,500
1.0	Solar Installations	N/A	N/A
Total Savings: 5.5 MW / 21,500 MWh	Total Cost: $14M	PAC B/C Ratio: 1.8	

*These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

Table 3.9: Energy Efficiency Expansion on the Rockaways – Illustrative Summary

Next Steps

- Obtain approvals for Rockaway Expansion program
- RFP for turn-key work, including equipment procurement, replacement and installation and program management, develop detailed costs estimates and schedules

3.2.7 Combined Heat and Power

Background

Combined Heat and Power ("CHP") systems use well-established technology for sequential generation of electric and thermal energy from a single fuel source, such as natural gas. In most CHP systems, a prime-mover reciprocating engine coupled to a generator produces electricity. The prime-mover also produces heat, which can be recovered from exhaust gases and used to produce steam and/or hot water in facilities with round-the-clock occupancy and reasonably steady electrical and thermal loads. Unlike traditional backup generators, CHP systems typically operate continuously at or near rated output over the equipment lifetime. Because of their ability to operate reliably when grid-supplied power is not available, the installation of CHP systems is encouraged by the Federal government and State regulatory agencies.[27]

Sample CHP Incentive Programs				
Entity	**Capacity Range (kW)**	**Incentive ($/kW)**	**Incentive ($/kWh)**	**Incentive Cap**
NJ State	</= 500	$2,000	$0	$2M, 30%-40% of Project Cost
	>500 – 1,000	$1,000	$0	
	>1,000 – 3,000	$550	$0	$3M, 30% of Project Cost
	>3,000	$350	$0	
NYSERDA - Upstate	All	$600	$0.10**	$1.5M, 50% of Project Cost
NYSERDA - Downstate*	All	$750	$0.10**	
PHI (MD only)	All	$250	$0.07***	$2M, 50% of Project Cost

* For NY City and Westchester County: the program is for CHP systems <1.3 MW (PON 2568);
For Nassau and Suffolk Counties: the program is for CHP systems >1.3 MW (PON 2701)

** Incentive is based on performance over a 24-month period

*** Incentive is based on performance over an 18-month period

Table 3.10: Sample CHP Incentive Programs

[27] On August 30, 2012, President Obama signed an Executive Order that directed certain federal executive departments and agencies to develop programs and policies to promote investment in industrial energy efficiency and CHP. States that encourage CHP installations include New York, California, Massachusetts, and Maryland.

CHP incentive programs achieve significant energy and demand savings. Customer load characteristics, high electricity prices, low natural gas fuel prices, and public incentives all factor into CHP economics.

PSEG Long Island Proposal

PSEG Long Island will consider offering incentives to install CHP for systems of 1.3MW or below. Systems of this size on Long Island are excluded from the existing CHP programs offered by NYSERDA. A capacity incentive based upon the installed capacity of generator and a production incentive proportional to the actual energy savings produced by the system could support certain projects. The capacity incentive could be paid in installments based on a project achieving certain milestones (i.e., signing contracts, beginning construction, commercial operation). The production incentive could be available during the first 18 months of operation. The actual incentive structure would be determined through further information gathering and analysis.

To further benefit from added reliability of CHP, the incentive could be increased if the CHP system supports critical infrastructure. We would define critical facilities as those so vital to health and safety that disruption of service could jeopardize the health, safety or security of the service area and its residents. Examples of critical infrastructure include nursing homes, public safety facilities (e.g., police, fire, hospital, emergency management), water and wastewater utilities, and communication facilities.

PSEG Long Island customer representatives would meet with customers to provide an assessment of CHP feasibility and arrange for developers to provide proposals. A key program measure for CHP is overall efficiency, which must be at least 65%. The level of marketing and customer education efforts will be reviewed annually and modulated as necessary based upon the level of CHP enrollments and MW savings realized.

Illustrative Market & Results

Our primary target market segments, their range of peak loads and target size are shown in Fig. 21:

PSEG Long Island Potential CHP Customer Segments		
Customer Segments	**Peak Load**	**Customers**
Large nursing homes	150-250 kW	50-75
Large industrial plants with 24/7 operation	500 - 4000 kW	15-20
Colleges and universities with dormitories	2,000-4,000 kW	15-20
Refrigerated warehouses and supermarkets	500-1500 kW	250-275
Large hotels with year-around high occupancy rates	500-3,000 kW	8-12
Large federal, state, local-govt. facilities, 24/7 occupancy (e.g., prisons, police stations)	500-2,500 kW	100-150

Table 3.11: PSEG Long Island Potential CHP Customer Segments

The proposed program size is 5 MW, though the actual program will be determined based upon project economics and customer participation.

Combined Heat & Power Illustrative Summary			
Project Size (kW)	**Number of Projects**	**Demand Savings (MW)**	**Energy Savings (MWh)**
100	3	0.30	2,340
200	3	0.60	4,680
400	4	1.60	12,480
750	2	1.50	11,700
1,000	1	1.00	7,800
Total	**13**	**5.00**	**39,000**
Total Savings: 5MW / 39,000 MWh		Total Cost: $5M	PAC B/C Ratio: 8.1

*These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

Table 3.12: PSEG Long Island CHP Program Savings

Next Steps

- Deepen the economic analysis and assess the incentives required relative to other resources
- Obtain approvals for the program proposal and the incentive levels
- Develop marketing plans for the customers and contractors
- Regularly monitor the CHP installation applications and progress, develop corrective action plans if the sign-up and installation progress is below the target

3.2.8 Geothermal Heating & Cooling

Background

Geothermal heating and cooling offers a unique opportunity for peak load reductions because the technology uses natural heat to provide heating, cooling, and often, water heating. Geothermal Heat Pumps ("GHP") use 25% to 50% less electricity than conventional heating or cooling systems. This translates into a GHP using one unit of electricity to move three units of heat from the earth. According to the U.S. DOE, GHP can reduce energy consumption up to 44% compared with air-source heat pumps and up to 72% compared with electric resistance heating with standard air-conditioning equipment.[28] GHPs also improve humidity control by maintaining about 50% relative indoor humidity, making GHPs very effective in humid areas. Retrofitting traditional HVAC equipment with a GHP system reduces peak demand and increases electricity use at a home or business in the winter, typically displacing fuel oil with more efficient geothermal heating. The net result is an improvement in electric system load factor and a reduction in greenhouse gas emissions, and may lower customer's heating costs.

A typical PSEG Long Island residential customer uses approximately 10,000 kWh annually and has an average peak demand of 4 kW. [29] The GHP system could reduce total electric and fossil fuel energy consumption for space heating, cooling, and water-heating by an estimated 4,500 to 5,000 kWh energy savings and 1.5 kW demand savings for a typical residential customer. [30]

[28] "Choosing and Installing Geothermal Heat Pumps." U.S. Department of Energy. http://energy.gov/energysaver/articles/choosing-and-installing-geothermal-heat-pumps. Accessed June 25, 2014.

[29] "Summary: Recent Trends in Residential Electricity, 2008." Long Island Power Authority.

[30] Using the "Climatemaster" GHP calculator for "Geothermal Heat Pump Costs", we conclude 55% energy savings for the following typical GHP retrofit for a 2,500 Sq. ft. house in NY with an Air Source Heat Pump ("ASHP") and average leakage and appliance efficiency for space heating, space cooling, and water heating when the ASHP is replaced by a GHP system.

Geothermal is, however, significantly more expensive than conventional HVAC. The installation costs range from $25,000 to $40,000 per GHP unit. The current federal income tax credits for a GHP installation cover 30% of the cost~~s~~. While this tax credit is scheduled to expire at the end of 2016, this federal program could be extended and continue to provide support for this technology.

The Authority currently offers rebates for geothermal units. The residential customer rebate is $1,500 per heat pump (regardless of size, for units ≥25 energy efficiency rating ("EER")). The commercial customer rebate for installations up to 11.25 tons per unit is $750 or $1,000 per ton depending upon the efficiency of the heat pump. Larger programs are evaluated on a case-by-case basis based upon projected energy savings, cooling loads and in the case of a retrofit, oil consumption. PSEG Long Island budgets about 200 rebates annually and we have met these goals since 2011.

PSEG Long Island Proposal

Based upon program experience and feedback from local contractors, increasing the rebate levels would stimulate the GHP market in Long Island. PSEG Long Island proposes expanding the geothermal incentive program to develop GHP in excess of existing program goals. PSEG Long Island proposes to:

- **Increase the residential rebate.** Considering that most of the units are 3-4 tons, we propose an average rebate of $2,250 per system. This amounts to approximately 8% - 10% of the net costs (i.e. after the tax credits) and would reduce the overall cost by approximately 40%.
- **Increase the commercial rebate.** Offer commercial customers a rebate of $900 or $1,200 per ton depending on the efficiency of the GHP. With average size of GHP units at 8 tons, we anticipate an average rebate of $9,000 per customer. This would reduce GHP cost by approximately 35% - 40%, depending upon unit size.
- **Customer education.** Targeted customer education and marketing programs will be offered in conjunction with the GHP contractors. This will highlight the benefits of GHP and energy savings.

Illustrative Market & Results

Considering the lead time needed for customer education and contractor marketing, we propose the following GHP installation plan:

Potential GHP Installation Plan	
Year	Number of Customers
2015	300-400
2016	400-600
2017	500-800
2018	500-900

Table 3.13: Potential GHP Installation Plan

Geothermal Heating and Cooling Illustrative Summary				
Type of Customers	Target Quantity	Average Rebate	Average kW Savings	Targeted MW Savings
Residential	1,500-2500	$2,250	1.5kW	2.3-3.7MW
Commercial	200-400	$9,000	4.0kW	0.8-1.6MW
Total Savings: 5 MW / 7,800 MWh		Total Cost: $10M		PAC B/C Ratio: 2.2

*These figures are illustrative, preliminary, and rounded. More detailed information on costs, benefits, and economic screening are provided in Appendix A.

Table 3.14: Potential GHP Installation Plan by Type of Customers

Next Steps:

- Obtain approvals for the incentive levels
- Develop marketing plans with the customers and contractor base
- Develop education materials and informational outreach plan
- Regularly monitor the GHP installation applications and progress

3.3 Capital Budget Investments

As part of PSEG Long Island's Utility 2.0 Plan, we propose that the Authority make certain capital investments. We have evaluated these investments for cost-effectiveness based on their resulting benefits of peak demand savings and deferred system upgrades and find them to be economically beneficial to the Authority and Long Island customers.

3.3.1 South Fork Improvements

The East End of Long Island represents the highest load growth region on Long Island (Figure 3.1). The existing transmission consists of a 69 kV and 23 kV system supplied by four 69 kV circuits - three from the South Fork and one from the North Fork. Given that the area is a narrow peninsula traditional routes for transmission supplies to the area are limited.

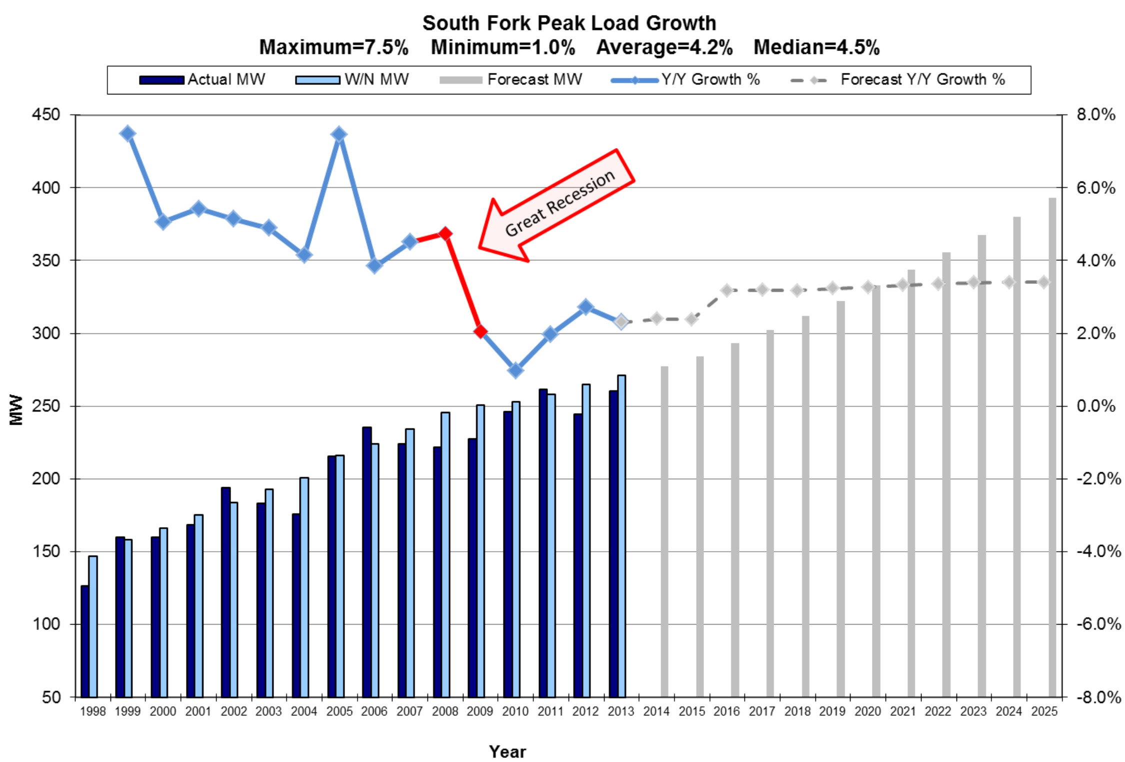

Figure 3.1: South Fork Peak Load Growth

PSEG Long Island has determined that a series of transmission reinforcements would be required on the South Fork of Long Island from 2017 – 2022 (Figure 3.2). Approximately $97 million (2012$) in conventional infrastructure was identified as being required by 2017 with an additional $197 million through 2022 for a total of approximately $294M. These costs consist primarily of new underground transmission cables and substation work. This capital reinforcement plan also requires continued reliance on the existing East End generation being available and able to provide its full capacity. However , these units are aging and becoming less reliable as time goes on, and they are less efficient and more polluting than modern generating units.

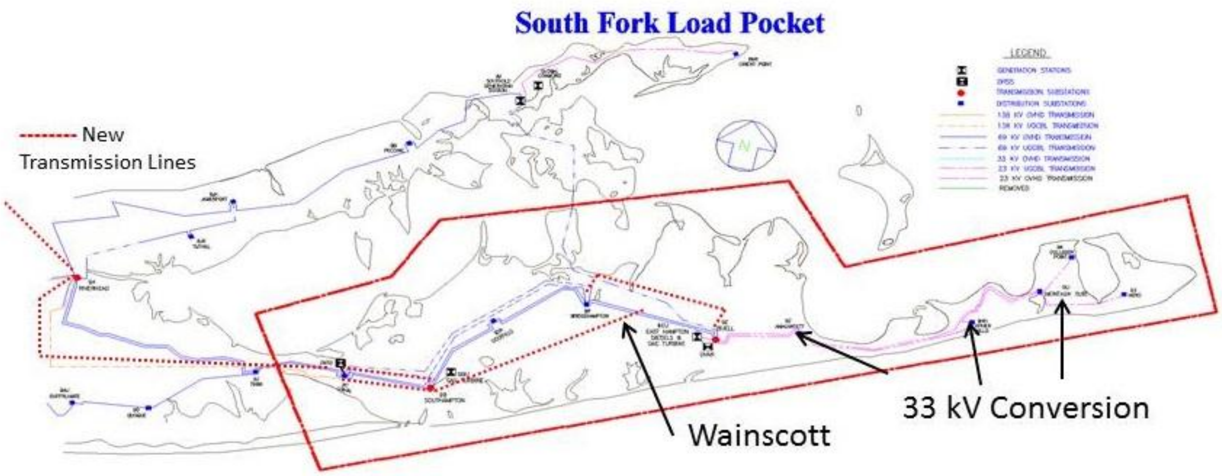

Figure 3.2: South Fork Transmission Expansion Plan

The area is extremely sensitive to local load conditions and is reliant on approximately 92 MW of generation, half of which were installed in the 1960s, on peak days for thermal and voltage support. Even with all generation available and online, the area requires special operating procedures to ensure reliability is maintained at the forecasted peak so as not to collapse the entire South Fork upon contingency. For 2013, in order to satisfy voltage criteria, generation on the East End was required when the South Fork reached 182 MW and special operating procedures were employed at a load level of 258 MW. Moreover these levels could be lower if any infrastructure is unavailable, such as the existing dynamic support systems at Canal and East Hampton substations.

Prior to PSEG Long Island's role as service provider, the Authority developed a plan to allow deferral of the transmission through the use of a series of alternatives: plans for expanded energy efficiency and direct load control in the South Fork, a locational premium included in the Clean Solar Initiative II ("CSI II") for 40 MW of solar PV in the South Fork, and energy storage options through the recent RFP for New Generation, Energy Storage and Demand Response Resources ("GSDR").[31, 32] Although the results of CSI II and the recent supply RFP are under review, and the RFP for energy efficiency and DLC is still in development, PSEG Long Island believes these resources can defer the need for transmission and peaking capacity on the South Fork.

Our recommended approach includes deployment of energy efficiency, DLC, solar PV, and energy storage, to better optimize power supply planning, all in complement with the Authority's GSDR. Our Plan builds upon the original the Authority concept with other Utility 2.0 concepts such as microgrids, battery storage, and improved transmission resiliency. Each component, as shown in Table 3.15, follows our guiding principles including empowering customers, enhancing reliability and resiliency, minimizing new infrastructure investments, and increasing utilization of system infrastructure.[33]

[31] CSI II provides fixed payments for electricity produced by approved photovoltaic systems over a fixed period of time. The program operates under a sell-all arrangement, where the full amount of energy production from the facility is sold to the utility (i.e., no on-site use). Systems from 100 kW to 2 MW that were not connected to the grid prior to the program's conditional acceptance period (on or around February 28, 2014) are eligible to participate. The program offers a 20-year contract at a rate determined through the Clearing Price Auction. A total of up to 100 MW of new solar generation will be supported by CSI II. The system size is determined as the lesser of the sum of the AC rated output of all inverters, or the PTC rating of the system multiplied by the inverter efficiency. Projects must be connected to the Authority grid at the distribution level, defined as 13.2 kV or below.

[32] The Authority's RFP for New Generation, Energy Storage, and Demand Response Resources was issued October 18, 2013, and closed March 31, 2014. the Authority solicited for three different blocks of resources: Block #1 included up to 250 MW of peaking generation or energy storage (up to 50 MW) in the East End; Block #2 included up to 880 MW of peaking generation and energy storage (up to 100 MW) in the EF Barrett and Holtsville areas; Block #3 included up to 500 MW of peaking generation, energy storage, and demand response system-wide. Proposals are currently under review.

[33] This table is illustrative of a possible solution focused on deferring transmission investments. The GSDR RFP is focused on two objectives; deferring transmission and replacing an aging generator fleet. The GSDR RFP may result in a recommendation to procure different amounts, timing, and location of resources. It is also possible that some of the peaking generation resources needs identified in the table may be procured through future solicitations.

South Fork Design Options	
Plan Components	Target Completion
Clean Solar Initiative II 21.6MW (selected) [34]	2016
Energy Efficiency - DLC 13 MW	2018
Peaking RFP I – 10 MW Montauk/Navy Rd and 15 MW Alternate Site to be determined	2019
Microgrid for additional resiliency	2019
Battery Storage[1] 2.5 MW	2019
Peaking RFP[2,3] - 25 MW S. Hampton	2021
Peaking RFP[2,3] - 25 MW S. Hampton and Deerfield	2023
Peaking RFP[2,3] - 25 MW Buell	2025
Peaking RFP[2,3] - 25 MW Buell	2027

Notes:

1. Battery Storage, due to its relative cost, is included only as an alternative in case of difficulties in achieving DLC and solar targets.
2. To the extent additional Solar, Energy Efficiency, and DLC can be achieved the need date for the peaking generation can be deferred or eliminated.
3. The results of the GSDR RFP may result in different timing, location and sizes of generation additions.

Table 3.15: South Fork Design Options

PSEG Long Island considered these components in different combinations and modeled the costs of these Utility 2.0 scenarios to compare with the base option of transmission reinforcements. The Utility 2.0 scenarios resulted in positive net present value (“NPV”) of savings each time. In addition, the Utility 2.0 Plan addresses all three of PSEG Long Island’s resiliency efforts by improving prevention, survivability and recovery. Results of this proposal will provide information to guide similar design

[34] The original CSI II called for a $0.07 premium to be paid to solar projects in the South Fork if the 40 MW was achieved. Under the terms of the offering, the clearinghouse auction evaluated applications in order of increasing pricing toward a total of 100 MW to determine the Final Clearinghouse Price which was $0.1688 per kWh for the 20 year term. Following conclusion of the review of the proposals 21.6 MW was selected in the South Fork. As such, no premium payment is included in our analysis.

solutions that are being considered across Long Island as deemed applicable and cost effective.

The following Figure 3.3 depicts the illustrative expansion of resources under the Utililty 2.0 Plan. The chart shows projected future load growth and the emerging suplpy need in 2016. The resource additions maintain the transmission loading to beneath the transfer limit.

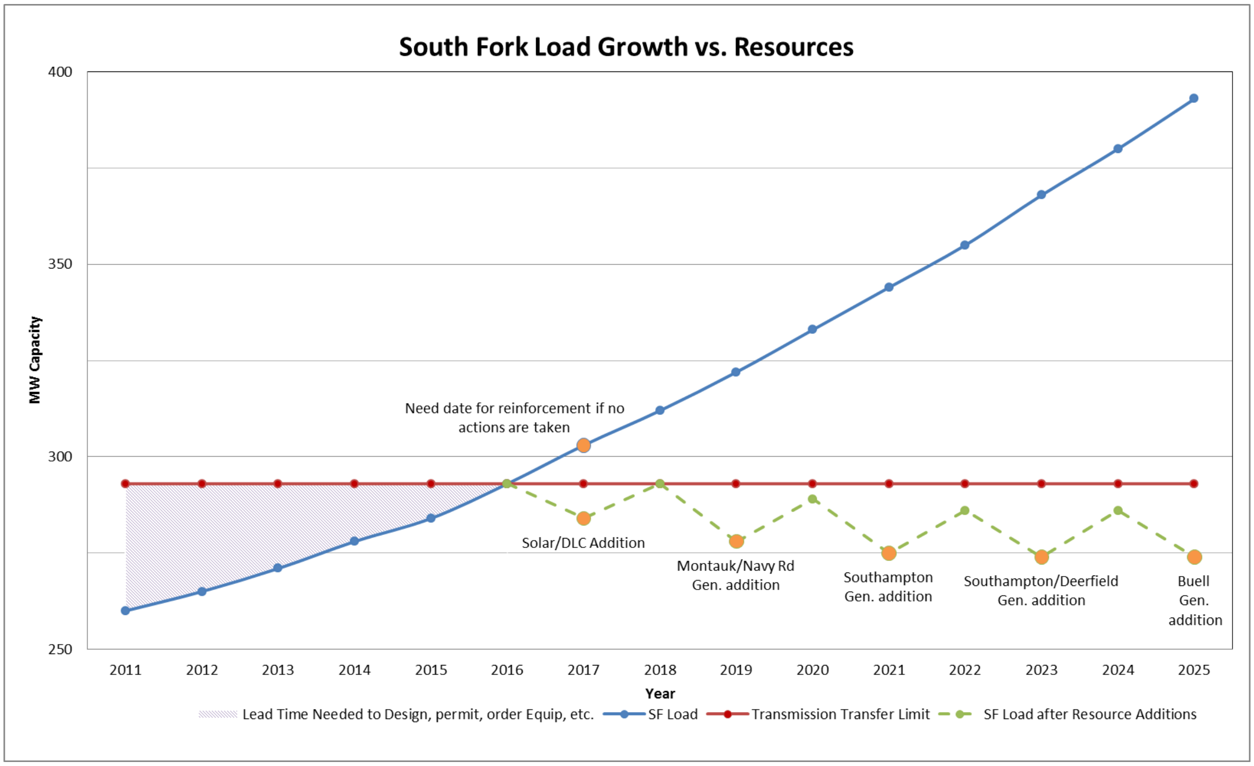

Figure 3.3: South Fork Load Growth vs Utility 2.0 Resources

Table 3.16 shows our economic analysis of the different scenarios, comparing installation of transmission lines (Scenario 1) to two approaches developed by PSEG Long Island (Scenarios 2 and 3). [35]

[35] Economic evaluation of the South Fork project followed different assumptions than other Utility 2.0 investments to better reflect the specific benefits of alternative options to a significant transmission upgrade project.

Scenario 2 assumes that the 21.6 MW of solar selected under CSI II comes to fruition, and combines that distributed generation with energy efficiency, DLC, and the ability to operate as a microgrid. In addition, with the implementation of alternative resources under Scenario 2, PSEG Long Island can phase-in the potential 125 MW peaking generation units selected from the GSDR, optimizing the supply timing and increasing the benefits of the proposals. If the results of the supply RFP can be arranged such that approximately 25 MW can be installed every other year starting in 2019 through 2027, the electric load growth can be met at a lower cost.[36] This phasing approach was included as part of Scenarios 2 and 3, and could result in potential savings of about $2 million in NPVRR in 2016 dollars for the period 2016 through 2035.

Estimated Capital and Net Present Value of Revenue Requirements of South Fork Improvements

		Millions of $s				
				NPV of RR (2016$)		
Scenario	**Comment**	**Capital ($s)**	**B/C Ratio**	**Total**	**Delta From Reference Case**	**B/C Ratio**
1) Reference (Transmission only) Case	Reference plan	$294	N/A	$298	Base	N/A
2) Utility 2.0 - 21.6 MW Solar, Phased Peaking Units, 13 MW DLC (Amortized) & Microgrid/Resiliency	LIPA RFP case adjusted for solar RFP results and phased peaking units,etc.	$172	1.7	$295	($2)	1.0
3) Utility 2.0 - 21.6 MW Solar, Phased Peaking Units, 13 MW DLC, Microgrid/Resiliency & 2.5 MW Battery	Case 3 with addition of 2.5 MW battery to supplement DLC and solar	$187	1.6	$322	$24	0.9

Notes:
Above are sample scenarios for future and will vary depending on response and ability to change RFP, results from DLC, Solar etc.
Capital is total expenditures in 2012 dollars and does not reflect timing of expenditures; NPV of RR based on 2016-2035 period.
Transmission plan includes 138 to 33 kV reinforcements to Riverhead and east to Montauk
Costs and sites for peaking units are preliminary estimates and subject to response to RFP , reflects estimated fuel penalty

Case 2 & 3 assumes energy efficiency/DLC and/or battery is funded by PSEG & Investor with 10 & 15 year amortization periods, respectively.

Table 3.16: Estimated Capital and Net Present Value of Revenue Requirements of South Fork Improvements

Scenario 3 includes battery storage to help meet the load demand requirements. Given its cost, Scenario 3 is being considered as a back-up to the recommended approach (i.e., Scenario 2). The benefit of adding battery storage is to levelize demands due to intermittency of the solar PV resources, meet higher than anticipated loads, and act as a backstop in case demand peaks later in the day when solar PV, energy efficiency, and DLC may not be available. Results show that the addition of 2.5 MW of battery storage reduces the benefit from $2 million in Scenario 2 to a penalty of about $24 million in Scenario 3. The battery, however, may turn out to be a good choice if the required amount of load reduction through energy efficiency and DLC cannot be obtained.

[36] Scenarios 2 and 3 are illustrative plans with one primary objective – deferral of transmission – and assume that aging (i.e., 40-year-old or more) generation will remain reliable and viable throughout the plan. The Authority's current GSDR RFP will also assess replacement of the existing aging fleet of generation.

Enhanced Resiliency Microgrid Potential

PSEG Long Island also notes the potential for demonstration of enhanced resiliency in the South Fork that can be enabled incorporating large scale microgrid concepts in the South Fork. One application of microgrid is the implementation of distributed generation on radial systems such as East End of Long Island.

Currently there are approximately 40 MW of generating units built in the 1960s and 1970s operating on the East End. These units are in need of replacement. One of the goals of the GSDR is to secure a combination of peaking generation and energy storage to add up to 250 MW of capacity on the East End. Energy storage units at several locations on the South Fork are intended to store excess renewable energy until it is needed at peak times. The energy storage resources could also assist black start resources by serving as a load. If these resources obtain black start capability, this initiative could result in the implementation of a large-scale microgrid application on East End that comprises both North and South Fork system.

Installation of 10 MW of new units that would interconnect with the Montauk substation (or future Navy Road substation) and in turn feed the Hero and Culloden Point substations could be expanded to create a microgrid. With a combined peak load of approximately 17 MW, the installation of resources that have black start capability, load following, and voltage controls, would allow for the operation of the area as an independent system. Besides helping to meet loads during normal peak periods, in the event of regional power outage or outage of the transmission lines to the west of Montauk substation, generation connected to Montauk could be used to pick up a portion of the area load. It could also directly feed Hero and Culloden Pt. substations or help pick up those loads through distribution ties. Other sectionalizing devices would need to be added. The costs of these microgrid attributes have been included in the scenarios described above.

PSEG Long Island Proposal

PSEG Long Island proposes to act as backstop provider of South Fork Improvements. To the extent that efforts to obtain adequate solar resources in the region from the market are unsuccessful, PSEG Long Island would finance solar resources in the South Fork to make up any shortage. In addition, PSEG Long Island can finance the costs of the DLC and energy efficiency, under the other Utility 2.0 Plan proposals, with incentives and marketing tailored for the South Fork. PSEG Long Island may also be available to develop the battery storage in the South Fork, if the approximately 13 MW of DLC needed in the South Fork is unavailable and an investor-financed storage project does not emerge.[37] These investments would be evaluated and the investment recovered similarly to the other Utility 2.0 investments described earlier in the Plan.

Implementation Plan:

The following Table 3.17 summarizes the South Fork proposal.

Elements of Utility 2.0 and Going Forward Recommendations			
Strategy	**Action**	**Target / Result**	**Recommendation**
Maximize Solar on East End	CSI II with 40 MW goal for East End	21.6 MW	Select developers for solar PV
Maximize Solar (continued)	280 MW Renewable RFP	TBD	Consider the benefits of additions on South Fork during evaluation of RFP. Consider issuance of offering(s) to include west facing feature to maximize capacity benefit.
Distributed Generation	Generation, Energy Storage, and Demand Response RFP	Emerging need must be met by 2019	Consider options for staging additions and sequencing the locations of capacity selection to optimize transmission deferral
Energy Efficiency/DLC	Utility 2.0 Programs	13 MW need is identified to complement solar PV	Modernize and expand DLC and energy efficiency under Utility 2.0 and target offerings to customers on South Fork.
Microgrid/Resiliency	Generation, Energy Storage, and Demand Response RFP	Potential independent island capability	Incorporate ASU and other controls to create microgrid.
Storage	Generation, Energy Storage, and Demand Response RFP	RFP responses under review	Assess need for battery storage and sizing of storage during evaluation of RFP.

Table 3.17: Elements of Utility 2.0 and Going Forward Recommendations

[37] Since the Authority was not successful in reaching its 40MW solar PV target for the South Fork in the CSI II program, PSEG Long Island looked at ways to address these lower values including incentivizing and/or mandating west facing solar, which has a higher output later in the day when demand in the South Fork peaks, as well as additional DLC. In order to ensure that the solar projects were still installed, PSEG Long Island also investigated whether the RFP terms could be modified such that the developers would continue to receive a price premium even though the 40 MW was not achieved. However, in discussions with the Authority, changes to the terms of the RFP are not allowed.

3.3.2 Large Customer Advanced Metering Initiative

Electric utilities across the U.S. have successfully deployed Advanced Metering Infrastructure ("AMI") and associated communications infrastructure to provide prompt and improved information to customers and improve operational efficiencies. By July 2013, almost 46 million customers in the U.S. will have some type of smart meter installed.[38]

The Authority has 7,500 smart meters currently operational as part of programs to collect interval consumption data as part of the Route 110 Corridor Project and at Hauppauge Industrial Park. In addition, the Authority replaced meters on Fire Island damaged during Superstorm Sandy with AMI. Communication systems, installed to support the 7,500 smart meters, include radios and repeaters which send energy consumption data to the PSEG Long Island Meter Data Management System ("MDMS"). This communication network is scalable and can be expanded as more smart meters are added in the aforementioned geographical locations or in new locations in Long Island.

PSEG Long Island recommends that the Authority expand its AMI investments in a phased approach to get to approximately 25,000 smart meters installed. In addition, we recommend expanding the AMI communication network to cover the entire service area. This will provide ready infrastructure to expand new smart meter installations on a selective basis based upon pre-determined criteria.

As we explain, the customers targeted for this program represent approximately 2% of customers but over 20% of load. Generally, these are large commercial customers with significant load that would benefit from enhanced access to meter data (see Table 3.18).

[38] "Report on Smart Meters Deployment." The Edison Foundation. August 2013.

Summary of AMI Deployment	
AMI Deployment	**Benefits**
6,000 Large C&I customers (Large customers representing 20% of load)	• Improve load management tools and capabilities at customer level, with better and faster data • Improve utility program offerings such as demand response programs with enhanced understanding of customer load and usage pattern
6,000 accounts with chronic long-term estimates	• Access difficult to reach customer meter locations. Improvement in the "read rate" performance by an estimate average of 0.75% - 1%. • Improve customer satisfaction with accurate data (scheduled monthly reads)
7,500 net-metered customers	• Offer enhanced functionalities for improved monitoring and controls • Improve distribution network planning and power quality with accurate and near-real time information
3,950 retail choice customers with accurate billing	• Provide accurate load settlements for retail-choice customers • Improve accounting of energy sales and energy consumption at the customer levels
155 ReCharge NY customers	• Provide accurate load settlements for NYPA program customers • Improve accounting of energy sales and energy consumption at the customer levels

Table 3.18: Summary of AMI Deployment

Large customers would be provided a web-based load monitoring system with improved information access and decision tools to lower energy consumption, shift the consumption patterns and lower overall costs. One study conducted by Lockheed Martin for its facilities concluded that these tools yielded greater than 3% energy savings due to near-real time monitoring capabilities. We conservatively target energy and demand savings of 1% for this program.

Smart meters can provide PSEG Long Island with improved understanding of the load flows and consumption patterns of the net metered customers and enhance integration of solar PV installations. Lacking visibility on the power quality impact of solar PV at the feeder and the substation basis, PSEG Long Island engineers take a conservative approach to allowed solar PV levels. An accurate and real-time availability of customer solar data and its impact on the distribution system may allow PSEG Long Island to integrate higher amounts of solar PV to the electric system.

AMI provides a technical foundation for improved load management and enables customer participation in demand response and other programs, where the cost of metering has been a barrier to entry. Better load research and the ability to see detailed customer energy usage profiles can facilitate improved demand side offerings, program design and supportive rate structures. Demand response participation can be validated by AMI data collection and provide PSEG Long Island planners with better confidence in distributed energy resources.

PSEG Long Island also proposes that the Authority scale the existing communication network to cover the entire service area. This facilitates integration of new smart meters with the existing MDMS. The scalable communication network can facilitate additional smart meter installations on a selective basis as more distributed resources are integrated into PSEG Long Island operations. Installing the communication network for the entire service area will ensure consistent system design and improved performance for the radio and wireless networks.

Preliminary cost estimates for this project, including meters, communications infrastructure, and installation costs, are approximately $12M. Assuming five-year useful life of the meters and corresponding 1% demand savings, and using the same cost effectiveness test screening methodology as other Utility 2.0 programs, PSEG Long Island estimates the AMI program is net positive. It is important to note the AMI investment is a foundation for further investment and education both to PSEG Long Island and its customers on the value of time sensitive end-use data and analysis. These benefits are difficult to quantify.

Section 4: Long-Term Vision

The proposed near-term investments in this inaugural Utility 2.0 Plan are intended to increase energy efficiency and the use of direct load control and distributed resources on Long Island. We believe these programs will result in lower customer bills near-term by avoiding costs of capacity, energy, and system upgrades that may otherwise be needed. This could include currently planned resource needs that represent a significant cost to customers. These investments would also give a head-start in cost-effectively meeting greenhouse gas reduction targets proposed by the EPA.

On a longer time horizon, this Plan can be a first step to transition the Authority into a "utility of the future." We believe this includes traditional responsibilities to provide safe, reliable, and resilient service to customers by deploying a diverse set of cost effective resources that maintain affordability and further reduce emissions. It may also include expanding the utility's role to integrate distributed resources and facilitate third-party and customer participation in markets for energy services. In its Report and Proposal filed in the REV Proceeding, DPS describes a Distribution System Platform Provider ("DSPP") that will "actively coordinate customer activities so that the utility's service area as a whole places more efficiency demands on the bulk system, while reducing the need for expensive investments in the distribution system as well."[39] PSEG Long Island agrees with DPS that the distribution utility is best suited as the DSPP. We believe the DSPP's role will include integrating DER solutions, facilitating a market for DER, participating in markets for energy solutions along with third party providers, and ensuring that all customers realize benefits.

We believe the combined approach of near-term investments by PSEG Long Island and the Authority and long-term development of a robust energy services market can provide long-term value for customers. In the near-term, utility planning efforts can identify cost-effective energy efficiency and distributed resources to be considered on equal footing with conventional resources. PSEG Long Island believes it is critical to target specific projects that can be deferred with alternative cost-effective resources. This way, resources will be deployed in a prudent manner that facilitates integration and avoids inefficient planning and investment.

[39] *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Case 14-M-0101, "Order Instituting Proceeding" (April 25, 2014)

Developing a market for third party providers is important. Customers will benefit from broad options for innovative services. But participation by third parties and customer-sited resources adds significant complexity to system planning and operations. The transition to "utility of the future" will require responsible deployment of technologies that enhance information sharing between customers and the utility, and add capabilities for customers to manage their energy use and costs.

In achieving the long-term transition envisioned in the REV proceeding, the traditional roles of the utility, its customers, and third party suppliers will evolve:

- **Utility responsibilities will expand to include enabling customer participation and balancing distributed energy resources.**

The utility will retain traditional responsibilities including grid interconnection, basic utility service, metering and billing, and customer data management. Planning and operations functions will continue to be core utility functions as well. Least cost planning can be best implemented by a centralized utility that has natural advantages including economies of scale and access to data. Planning and operations will need to adapt to manage and integrate decentralized electricity production as customer-sited resources are added to the system. The utility should be incented to focus on maintaining reliability with the lowest cost resource, including end use efficiency, direct load control, or other options.

An important role for the utility will be ensuring universal access to programs. Certain customer segments lack the resources to invest in energy services despite the potential economic benefits. Universal access is a basic tenet of utility service and as new options become available it will be important that all customers share in the benefits. The utility can enable participation by providing low cost, patient capital that affords customers the financial flexibility to implement cost effective measures. This philosophy guides our proposals for hospital customers and customers in the Rockaways.

The utility will also seek opportunities to expand behind the meter with products and services. The utility has a direct relationship with customers and experience with analysis of consumption that will help design tailored energy options. As examples, the investments and programs implemented by the Authority as well as PSEG's New Jersey utility affiliate, PSE&G, have successfully provided customers with energy efficiency programs, solar PV incentives, and other energy services. As noted in this Plan, we believe that PSEG Long Island can more broadly apply these concepts and extend to Long Island customers innovative energy service offerings.

Utility 2.0 should also create new applications of advanced technologies that address the peak demand that drives so many capital budgeting decisions. For example, AMI and improved communications instantaneously, automatically, and remotely provides utilities with useful information that enhance operations, asset management, and customer billing. All of this improves the customer experience. Advanced meters measure bi-directional power flow and provide real-time signals that enhance the value of energy end use management and enable participation in demand response programs.

Utilities will experience more demands from customers seeking to add advanced technologies to the power system. For example, some critical facilities and other customers requiring uninterrupted electric service (e.g. hospitals, data centers, and emergency services) are exploring enhanced resiliency through backup generation, energy storage, and microgrids to maintain service through significant utility service disruptions. Each customer will have its own unique set of requirements. PSEG Long Island can help customers understand the complexities and the unique requirements of advanced technologies.

- **Customers will benefit from enhanced energy service options and, in some cases, new opportunities to provide supply- and demand-side resources.**

Utility 2.0 has the potential to enhance customers' energy choices in a significant way not experienced since restructured energy markets provided energy supply choices varied by fuel source, contract tenure, and other factors. New technologies will add capabilities to manage energy end use and costs, and to participate in markets directly or through programs offered by utilities and third party providers.

However, the reality is that most customers lack the tools and sophistication to meaningfully manage their energy use. Enhancing the customer experience starts with providing additional data to customers on their end use energy consumption. Benchmarks and, potentially, real-time information and analysis are critical. Just as important is providing tools and resources to analyze this data and act on energy services opportunities. For customers to participate they must understand the capabilities and limitations of demand side management and the capacity for the utility system to integrate distributed resources. When consumers shift from load to power generation it creates new challenges for utility planners managing a portfolio of diverse system resources.

Likewise, customers will need the ability to realize the appropriate value of demand and energy savings to invest properly. Value should be determined in such a way that avoids providing undue competitive advantages to certain resources and/or technologies. Rate tariffs can be redesigned to ensure that a modern grid successfully integrates disaggregated resources and maintains reliable core services at fair and reasonable cost. Rates that signal the time-of-use value of energy end use management will be needed to enable proper valuation of customer resources. When customers can value the price differential between peak and off-peak periods, they will be incented to respond accordingly.

Issues of equality will become priority with widespread deployment of distributed resources. Cross subsidization of programs by non-participating customers is an issue that will be more important to address as some customers are unable or unwilling to invest in distributed resources. Net metering is a good example of this issue; under some net metering rules, distributed generation is compensated for excess energy at full retail rates. Customers able to take advantage can avoid the full cost of their bill although they benefit from utility services. Tariffs should ensure that all customers that benefit from utility service pay their fair share of costs, and that utilities are compensated for their role in ensuring reliability of service, as well as any expanded role they are expected to hold in the future.

- **Third party providers will monetize the value of distributed resources and provide value and services to customers.**

Energy service companies ("ESCOs") and other third party providers will expand from retail supply offerings to more value added and demand side offerings as customers demand these services. Many customers facing the new and complicated responsibility of managing energy consumption data may seek consultation with third parties that can provide consultation, directly manage end use, or otherwise monetize the value of energy savings. A robust market of third party providers will enhance the innovation offerings available to customers.

The relationship between utilities and ESCOs will be critical to providing customers with a broad set of energy options. Utilities and ESCOs will need to determine how to share in the responsibility of serving customers. Ultimately, it will be the utility's responsibility to maintain distribution service and communicate with its customers. Customer-sited generation resources will need to be managed to maintain reliability of the distribution system, necessitating direct contact between the utility and the party managing the resource (i.e., customer or ESCO).

Section 5. Stakeholder Outreach

Throughout development of this Plan, PSEG Long Island has engaged with various stakeholders in New York and on Long Island to try to develop a proposal that is consistent with the needs of our customers, the Authority, and New York State. We will solicit feedback to refine this plan and optimize its implementation and our commitment to stakeholder input will remain a primary objective of subsequent annual reviews of this initial proposal.

PSEG Long Island plans to hold a Technical Conference on our Utility 2.0 Plan on July 24, 2014. The purpose of the Conference will be to describe the Plan and receive comments on our proposed scope of work, timeline and rate impact from interested stakeholders. In addition, we can hold additional forums as appropriate to engage community leadership, residents, and businesses on the opportunities and incorporate their feedback into the development of executable plans. The meetings may be across Long Island, and could also be located in the Rockaways and South Fork load pockets, which have been identified for targeted investments in our proposal due to their location-specific needs.

The Environmental Advisory Committee established as required per the OSA has been engaged since early drafts of this proposal to comment on the direction of our recommendations. This Committee will receive quarterly updates on progress of PSEG Long Island's energy efficiency and renewable investments throughout the life of the program.

Our approach to public outreach will continue throughout subsequent annual updates to the Utility 2.0 Plan. PSEG Long Island will be proactive in engaging customers and educating them on their energy use and the options to contain costs through efficiency investments. When reliability needs are identified, we will review the need with the community and present various solution options, including Utility 2.0 concepts and traditional solutions. Our goal is to clearly communicate the reliability, affordability, environmental, and community considerations of the investments that PSEG Long Island and the Authority make in Long Island.

Appendix A

Cost Effectiveness Tests

Assumptions, Methodology, and Results

Introduction

PSEG Long Island has maintained a focus on the cost effectiveness of program investments in its proposed Utility 2.0 Plan. Cost effectiveness is a measure of the investment's relative economic performance and attractiveness. The process of evaluating cost effectiveness includes estimating the net present value of benefits and program costs over the expected useful life of the measure and/or program. For our purposes, benefits include the avoided costs of capacity and energy resulting from the program. In the case of the South Fork Improvements program, the evaluation includes capital investments deferred or displaced by a Utility 2.0 solution. Generally, costs include some combination of measure costs, labor/installation costs (as applicable), customer financial incentives, and administrative costs, as described below.

Cost Effectiveness Tests

Utility regulators have several cost effectiveness tests to choose from in evaluating energy efficiency and other clean energy investments. The difference in tests is the scope of costs included in the calculation – some tests limit the scope to the perspective of the utility or program administrator while others incorporate participant and other customer costs.

PSEG Long Island measured two cost effectiveness tests to screen the Utility 2.0 programs: the Program Administrator Cost test and the Total Resource Cost test. We are in favor of using the Program Administrator Cost test to evaluate the economic viability of Utility 2.0 programs, and we describe our rationale below, as well as a high level description of each test.

1. **Program Administrator Cost ("PAC") Test** – Also known as the Utility Cost Test ("UCT"), this test incorporates costs incurred by the utility or program administrator (in this case, PSEG Long Island). This includes measure costs, labor and installation (where applicable), customer incentives, and program overhead costs (e.g. program administration, marketing). This test provides a clear picture of whether the program is balanced from the perspective of utility or program administrator. The PAC test does not include customer benefits of avoided fuel

costs (e.g. home heating oil), water savings, or other externalities, and does not include customer share of investment in energy conservation measures.

2. **Total Resource Cost ("TRC") Test** – Also known as the "All-Ratepayer Test", the TRC compares the value of avoided costs to the full costs of energy conservation measures, including labor and installation costs and program administration costs incurred by the utility and/or program administrator and the full incremental cost of upgrading equipment incurred by participant customers. A TRC ratio greater than 1.0 indicates that the investment results in lower resource costs for the utility and lower average energy costs for both participant and non-participant customers.

   Importantly, the TRC considers customer incentives provided by the utility and/or program administrator to be pass-through transfer of costs, netting out of the total costs included in the test. This practice ignores the incentive level needed to drive investment and creates a situation where participant customers may receive unbalanced benefits from the program.

PSEG Long Islands favors using the PAC Test for its Utility 2.0 Plan for several reasons:

- With the PAC test, the rebate is set at a level that is cost-effective for PSEG Long Island and the customer can decide whether or not to pay the incremental cost.

- The PAC test implicitly accounts for externalities because customers' willingness to pay is proportional to their perceived overall benefit, including environmental benefit, customer comfort, and customer convenience. While the TRC can be modified to include externalities, it can be difficult to quantify those benefits.

- The PAC test can limit rate impacts because it provides an incentive to achieve the same results with lower costs. The TRC considers customer incentives a pass-through cost with no effect on the benefits-to-cost ratio.

- All costs in the PAC test flow through electric rates. The test is analogous to supply-side resource acquisition where all costs flow through rates to customers. Our proposal to amortize costs over the expected life of equipment (i.e. eight to twelve years) would bring supply and demand side resources even closer into alignment.

Cost Effectiveness Test Assumptions

Study assumptions are grounded in the experience of PSEG Long Island staff and other research conducted in development of the Utility 2.0 Plan, including interviews and data requests of subject matter experts from demand response providers, energy service companies, technology providers, and energy service program managers at our New Jersey utility affiliate, PSE&G. However, our assumptions should be considered preliminary and subject to change as actual costs and program economics will depend on approval of the Utility 2.0 Plan and solicitation of pricing from equipment vendors and installation contractors.

Program Benefits

- Avoided Costs of Capacity & Energy

The benefits of Utility 2.0 are the net present value ("NPV") of the avoided supply costs – specifically energy and capacity savings – resulting from the measure or program undertaken. The value of avoided costs were developed in a benchmark study blending four proposals for combined-cycle gas turbine ("CCGT") generating units received in 2011 in response to the Authority's RFP to Provide Electric Capacity, Energy & Ancillary Services ("supply RFP"). The values were updated in January 2013 with more recent bid evaluation information and natural gas prices. A sample is provided below:

Sample of Avoided Costs (2015 – 2026)		
Year	Capacity ($/kW-yr)	Energy ($/kWh)
2015	$301.24	$0.038
2016	$303.53	$0.043
2017	$305.88	$0.046
2018	$308.31	$0.050
2019	$310.79	$0.054
2020	$313.35	$0.058
2021	$315.98	$0.060
2022	$318.69	$0.061
2023	$321.47	$0.064
2024	$324.33	$0.065
2025	$327.27	$0.067
2026	$330.29	$0.069

For the benchmark study, the cost of a 20-year power purchase agreement was modelled, with all power plant construction costs included in the capacity charge, along with the estimated cost of electrical interconnection and system upgrades. The CCGT plant was assumed to operate at an 86.5% annual capacity factor and a 6,904 BTU/kWh heat rate. Environmental costs were included to the extent required to comply with the Regional Greenhouse Gas Initiative requirements and other permits. These assumptions are consistent with the manner in which the Authority would be expected to procure its next unit of base load capacity.

Historically, the Authority used a baseload CCGT as the reference case for establishing capacity and energy savings for the screening of its Efficiency Long Island portfolio. Primarily, this was because the Electric Resource Plan called for the next segment of capacity to be from a CCGT plant for purposes of meeting the Authority's energy resource mix. The decision was also supported because the size of the Efficiency Long Island portfolio (i.e., 520 MW) and its associated load factor are greater than what would be expected of a peaking unit, and more comparable to a CCGT. Similarly, the proposed size (i.e. 185 MW) and annual load factor (i.e., ~18%) of the proposed Utility 2.0 Plan is not comparable to a peaking plant. While the potential load factor of our proposed Utility 2.0 investment is well below the anticipated capacity factor of a new CCGT (i.e., 86.5%), it is also well above the anticipated capacity factor of a peaking plant (i.e., 1.0 - 5.0%). Moreover, based on recent bids, capacity cost for peaking plants is not significantly lower than CCGT plants on Long Island.

- Capacity & Energy Savings

The resulting savings from Utility 2.0 programs are estimated based on PSEG Long Island experience and research and analysis of energy conservation measures. Assumed achievable annual savings for each program are as follows:

	Annual Capacity (kW)	Annual Energy (kWh)
Utility 2.0 Investments		
DLC Expansion & Modernization	100,000	2,700,000
Energy Efficiency Expansion at Rockaways		
Residential Lighting	1,000	9,071,462
Residential Room Air Conditioning	1,500	424,181
Residential Refrigerators	550	2,672,956
Commercial Solar	1,000	2,823,529
Commercial Direct Install Lighting	1,500	6,512,174
Rockaways Total	5,550	21,504,302
Hospital Energy Conservation Program	5,000	28,000,000
Solar PV (over 200kW)	28,510	80,498,735
Residential Home Energy Management	10,000	25,000,000
Geothermal Heating & Cooling	5,000	7,820,000
Combined Heat & Power	5,000	39,000,000
Incremental Energy Efficiency		
Energy Efficient Products	3,000	21,381,000
Cool Homes	2,000	1,622,000
CEP Mid-market	5,000	18,155,000
Incremental EE Total	10,000	41,158,000
Total Utility 2.0	**169,060**	**245,681,037**
Capital Budget Investments		
South Fork Improvements		
Scenario 3 - Solar PV and DLC	TBD	TBD
Scenario 4 - Solar PV, DLC, and Energy Storage	TBD	TBD
Large Customer AMI	15,000	45,000,000
Total Capital Budget	**15,000**	**45,000,000**
Utility 2.0 Overall	**184,060**	**290,681,037**

Program Costs

The other half of the PAC test equation is the NPV of the program costs including cost of measures, labor, incentives, and administration. Again, these costs are estimated based on our experience, research of similar programs in the industry, and primary research with subject matter experts. These preliminary cost estimates would differ from actual costs of programs procured through RFP from implementation contractors. Some points to consider:

- Measure costs include equipment costs only.
- Labor costs are included in cases where it is expected that PSEG Long Island and/or an implementation contractor would provide the service. For example, we may procure local contractors in the Rockaways to aid in installation of energy efficiency equipment.
- Incentive costs represent the expected level of financial support needed to encourage customer participation. These are generally estimated based on PSEG Long Island experience with existing programs and feedback from electric customers.
- Administration costs are assumed at 5% of total program costs for programs that would be similar in nature to existing energy efficiency and renewables programs. For the proposed Combined Heat & Power program we assume 10% to be conservative given the lack of history with CHP within the company.

	Program Cost (2015$)
Utility 2.0 Investments	
DLC Expansion & Modernization	$63,000,000
Energy Efficiency Expansion at Rockaways	
Residential Lighting	$585,954
Residential Room Air Conditioning	$2,967,629
Residential Refrigerators	$2,781,450
Commercial Solar	$3,750,000
Commercial Direct Install Lighting	$3,195,089
Rockaways Total	$13,280,122
Hospital Energy Conservation Program	$28,104,925
Solar PV (over 200kW)	$42,764,953
Residential Home Energy Management	$8,400,000
Geothermal Heating & Cooling	$9,450,000
Combined Heat & Power	$5,000,000
Incremental Energy Efficiency	
Energy Efficient Products	$9,000,000
Cool Homes	$6,000,000
CEP Mid-market	$15,000,000
Incremental EE Total	$30,000,000
Total Utility 2.0	**$200,000,000**
Capital Budget Investments	
South Fork Improvements	
Scenario 3 - Solar PV and DLC	TBD
Scenario 4 - Solar PV, DLC, and Energy Storage	TBD
Large Customer AMI	$12,000,000
Total Capital Budget	**$12,000,000**
Utility 2.0 Overall	**$212,000,000**

Expected Useful Life of Measures

Savings are assumed to extend over the useful life of measures, with future benefits discounted to NPV in the cost effectiveness test calculation. The expected useful life of energy conservation measures is a key input to this analysis.

	Measure Life (Years)
Utility 2.0 Investments	
DLC Expansion & Modernization	10
Energy Efficiency Expansion at Rockaways	
Residential Lighting	6.5
Residential Room Air Conditioning	12
Residential Refrigerators	15
Commercial Solar	25
Commercial Direct Install Lighting	16
Rockaways Total	N/A
Hospital Energy Conservation Program	20
Solar PV (over 200kW)	25
Residential Home Energy Management	20
Geothermal Heating & Cooling	20
Combined Heat & Power	20
Incremental Energy Efficiency	
Energy Efficient Products	10
Cool Homes	18
CEP Mid-market	16
Incremental EE Total	N/A
Total Utility 2.0	**N/A**
Capital Budget Investments	
South Fork Improvements	
Scenario 3 - Solar PV and DLC	TBD
Scenario 4 - Solar PV, DLC, and Energy Storage	TBD
Large Customer AMI	5
Total Capital Budget	**N/A**

Discount Rate

Utility 2.0 investments have been discounted using a rate of 7.5%. The Large Customer AMI program has been discounted using a rate of 5.5%. The South Fork Improvements were evaluated using appropriate discount rates for individual components of the Proposal (see below).

Test Results			Levelized Costs	
	PA Ratio	TRC Ratio	$/kWh	$/kW
Utility 2.0 Investments				
DLC Expansion & Modernization	3.7	3.7	$3.40	$91.78
Energy Efficiency Expansion at Rockaways				
Residential Lighting	5.9	5.9	$0.01	$124.83
Residential Room Air Conditioning	1.4	1.4	$0.90	$255.77
Residential Refrigerators	1.1	1.1	$0.12	$572.91
Commercial Solar	1.5	0.8	$0.12	$336.42
Commercial Direct Install Lighting	2.5	2.5	$0.05	$233.01
Rockaways Total	1.8	1.5	$0.08	$288.63
Hospital Energy Conservation Program	1.2	0.9	$0.10	$551.37
Solar PV (over 200kW)	3.9	0.8	$0.05	$134.57
Residential Home Energy Management	1.3	1.3	$0.13	$323.01
Geothermal Heating & Cooling	2.4	1.4	$0.12	$185.39
Combined Heat & Power	8.1	1.7	$0.01	$98.09
Incremental Energy Efficiency				
Energy Efficient Products	1.6	1.0	$0.06	$437.06
Cool Homes	1.3	0.6	$0.38	$309.09
CEP Mid-market	1.7	1.0	$0.09	$328.17
Incremental EE Total	1.6	0.9	$0.09	$350.01
Total Utility 2.0	**2.9**	**1.2**	**$0.09**	**$152.11**
Capital Budget Investments				
South Fork Improvements				
Scenario 3 - Solar PV and DLC	1.0	N/A		
Scenario 4 - Solar PV, DLC, and Energy Storage	0.9			
Large Customer AMI	2.3	2.3	$0.07	$197.73
Total Capital Budget	**N/A**			
Utility 2.0 Overall	**N/A**			

As described below, the South Fork Improvements PAC ratio represents the benefit of savings due to change in NPV of revenue requirement compared to a transmission-only base case, and capital cost associated with applicable investments. The TRC is not applicable to the South Fork Improvements analysis.

Levelized costs are presented for illustrative purposes but there is an important limitation to its use as a comparison metric. In most cases, levelized costs are not the accurate representation of the actual cost of delivered savings. Energy conservation measures that deliver substantial amounts of both energy and capacity savings have two value streams resulting from the same total project costs. However, in the derivation of the levelized cost, the full cost is compared to only one stream of value at a time (i.e., capacity or energy). This results in the levelized cost being substantially higher than actual.

South Fork Analysis

The South Fork program was analyzed using conventional utility investment methods. This is appropriate as the program is being offered as an alternative to a typical utility transmission investment required to meet reliability standards. The results are similar to the PAC test.

For comparison purposes the net present value of revenue requirement (“NPVRR”) from the alternatives was used. The Utility 2.0 solutions include solar PV, energy efficiency, direct load control, and energy storage to reduce demand in the area and defer the need date of transmission improvements. The costs of these alternatives based on the type of investment and life were included in the analysis of NPVRR.

The starting point or reference case was the expansion of the transmission system on the South Fork. This entailed transmission investments of approximately $294 million (in 2012$) from 2017 through 2022. Using a discount rate of 5.5%, the analysis yielded an estimated NPVRR of $298 million (2016$) for the 2016-2035 period.

For Scenario 2, the recommended plan, we used projected marginal market capacity prices to represent the avoided cost resulting from load reduction. Implicit in the prices is a 17% reduction in reserve requirement resulting from the reduced demand. That is, the capacity prices reflect an increase of 17% over projected capacity market prices to reflect the increased savings from avoidance of the reserve requirement. We also included the effects of incremental cost of capital and reduced capacity factor for distributed solar PV units versus combined cycle, as well as the cost of energy efficiency and direct load control net of avoided capacity costs. For energy efficiency and direct load control it was assumed that PSEG Long Island would make the investments and allow amortization over a 10 year period. For solar PV, no incremental costs or benefits were included as it was assumed that the Plan includes relocation of units that would have been installed elsewhere on the system. Scenario 3 results in reduced capital expenditures of $172 million (2012$) with a NPVRR of $295 million (2016$), and a Benefit to Cost ratio of 1.0.

Scenario 3 includes the potential installation of 2.5 MW of battery storage. Storage is currently not expected to be economic and results in a penalty compared to the proposed Scenario 2. It would be installed only if the demand reductions cannot be achieved using other methods. Our analysis assumes that any required storage would be competitively bid and privately developed, with PSEG acting as a back-stop provider if a third party provider fails to emerge.

<u>Alternative Assumptions and Results</u>

PSEG Long Island also considered the NYISO's capacity market demand curve as additional reference for capacity pricing. The NYISO uses an administratively-determined cost of new entry ("CONE") of a reference unit (i.e. peaking unit), and nets out the expected energy and ancillary services revenues to arrive at the value needed to incent construction of the unit ("Net CONE"). Because we need a 25-year forecast of avoided costs for the Utility 2.0 Plan, we escalated the three-year NYISO demand curve values by a rate consistent with the assumptions of the benchmark study. Below is a sample of the avoided costs we've derived using NYISO's capacity market demand curve:

Sample of Avoided Costs (2015 – 2026)		
	NYISO	
Year	Capacity ($/kW-yr)	Energy ($/kWh)
2015	$153.63	$0.06
2016	$157.01	$0.07
2017	$158.22	$0.07
2018	$159.48	$0.08
2019	$160.76	$0.08
2020	$162.09	$0.09
2021	$163.45	$0.09
2022	$164.85	$0.09
2023	$166.28	$0.10
2024	$167.76	$0.10
2025	$169.28	$0.10
2026	$170.85	$0.11

However, there are a few drawbacks with using the NYISO demand curve as an alternative means of estimating avoided capacity and energy costs. First, as noted, the NYISO demand curve only estimates prices for the next three years, rather than the 25-year period required for evaluation of energy efficiency and renewable programs. Second, the Authority's resource procurement is generally driven by its on-Island capacity requirements, and there is limited on-Island capacity available in the markets to meet this need. This is opposed to its statewide requirements that can be met through the capacity markets. Third, by tariff the NYISO demand curve must represent a peaking unit regardless of whether new planned energy resources include a baseload CCGT plant. Therefore, the NYISO demand curve significantly undervalues capacity relative to actual bids received as part of the supply RFP and the more recent RFP for New Generation, Energy Storage and Demand Response Resources.

Using this alternative avoided costs assumption in place of those in the benchmark study, and holding constant all other assumptions of program costs, measure life, and discount rates, we arrive at the following cost effectiveness test results for Utility 2.0 investments and the Large Customer AMI program:

			Levelized Costs	
	PA Ratio	TRC Ratio	$/kWh	$/kW
Utility 2.0 Investments				
DLC Expansion & Modernization	1.9	1.9	$3.40	$91.78
Energy Efficiency Expansion at Rockaways				
Residential Lighting	5.3	5.3	$0.01	$124.83
Residential Room Air Conditioning	0.8	0.8	$0.90	$255.77
Residential Refrigerators	0.9	0.9	$0.12	$572.91
Commercial Solar	1.2	0.6	$0.12	$336.42
Commercial Direct Install Lighting	2.1	2.1	$0.05	$233.01
Rockaways Total	1.4	1.2	$0.08	$288.63
Hospital Energy Conservation Program	1.1	0.8	$0.10	$551.37
Solar PV (over 200kW)	3.0	0.6	$0.05	$134.57
Residential Home Energy Management	0.9	0.9	$0.13	$323.01
Geothermal Heating & Cooling	1.5	1.0	$0.12	$185.39
Combined Heat & Power	7.9	1.6	$0.01	$98.09
Incremental Energy Efficiency				
Energy Efficient Products	1.4	0.9	$0.06	$437.06
Cool Homes	0.8	0.4	$0.38	$309.09
CEP Mid-market	1.3	0.8	$0.09	$328.17
Incremental EE Total	1.2	0.7	$0.09	$350.01
Total Utility 2.0	**2.0**	**0.8**	**$0.09**	**$152.11**
Capital Budget Investments				
South Fork Improvements*				
Scenario 3 - Solar PV and DLC	1.0	N/A		
Scenario 4 - Solar PV, DLC, and Energy Storage	0.9	N/A		
Large Customer AMI	1.7	1.7	$0.07	$197.73
Total Capital Budget	**N/A**			
Utility 2.0 Overall	**N/A**			

*See above for detail above regarding economic analysis specific to the South Fork Improvements.

Appendix B

PSEG Long Island

"Utility 2.0" Long Range Plan

Summary of Principal Terms and Conditions

This Term Sheet is intended to provide a summary of the principal terms and conditions of a proposed amendment (the "Amendment") to the Amended and Restated Operations Services Agreement (the "OSA") between the Long Island Lighting Company d/b/a LIPA, a New York corporation ("LIPA"), and PSEG Long Island LLC (the "Service Provider"), dated December 31, 2013, to give effect to the Long Range Plan (as defined in the OSA). This Term Sheet has been prepared for discussion purposes only and does not create any legal obligation. Capitalized terms have the meanings assigned to them in the OSA unless otherwise defined.

Utility 2.0 Capital Expenditures:

Under the Long Range Plan, the Servicer Provider or its affiliate will invest an agreed amount of capital from 2015 through 2018 in targeted programmatic investments related to the "Utility 2.0" Long Range Plan, including in energy efficiency, demand response, distributed generation and related programs within the Service Area (the "Utility 2.0 Capital Expenditures").

The Utility 2.0 Capital Expenditures will be treated as capital improvement expenditures under the OSA and will be budgeted as a Capital Budget under the OSA (such portion of the Capital Budget relating to Utility 2.0 Capital Expenditures, the "Utility 2.0 Capital Budget").

As compensation for Utility 2.0 Capital Expenditures made by the Service Provider or its affiliate, LIPA shall make monthly payments pursuant to an agreed upon payment schedule ("Payment Schedule") starting with the month immediately following the month in which the Program expenditure is made but not earlier than the implementation of the rates to be put in effect pursuant to the rate case to be filed February 1, 2015. The Utility 2.0 Capital Expenditures will otherwise be treated as Pass-Through Expenditures under the OSA and subject to the same payment terms and requirements thereof, including the 3-month pre-funding requirement.

Utility 2.0 Incentive Payment

The Service Provider will be entitled to receive incentive compensation or obligated to pay penalties in relation to the performance of the Utility 2.0 program (the "Utility 2.0 Incentive Payment"). Specifically, the annual rate of Utility 2.0 Incentive Payment will be calculated based on two performance factors: Program Cost Effectiveness and Peak MW Savings.

Program Cost Effectiveness: the Program Administrator Cost ("PAC") test will measure the program administrator benefits to cost ratio. The baseline PAC ratio will be set at 1.1, and the annual rate of incentive compensation or penalty payable starting in respect of 2016 on the aggregate amount of Utility 2.0 Capital Expenditures made as of the time of calculation shall be calculated as follows:

(i) for each 10% of over-performance over the baseline PAC ratio of 1.1, a multiplier will be applied to the repayment rate, annually, as illustrated below, up to a maximum of 1.3x multiplier; or

(ii) for under-performance below the baseline PAC ratio of 1.1, a multiplier will be applied to the repayment rate, annually, as illustrated below, down to a maximum of 0.9x multiplier.

Peak MW Savings: in the event the Servicer Provider is entitled to incentive compensation for over-performance under the Program Cost Effectiveness formula above (the "PCE formula"), the amount calculated under the PCE formula shall be further adjusted based on the satisfaction rate of the Peak MW Savings Goal as follows:

(i) If 100% or more of the Peak MW Savings Goal is met, the Service Provider will be entitled to 100% of the incentive compensation calculated by the PCE formula; and

(ii) if less than 100% of the Peak MW Savings Goal is met, the incentive compensation calculated by the PCE formula and payable to the Service Provider shall be decreased on a straight-line basis so that at 80% satisfaction of the Peak MW Savings Goal, the incentive compensation amount will be zero. There will be no penalty for satisfying less than 80% of the Peak MW Savings Goal.

The Utility 2.0 Incentive Payment amount calculated in accordance with the above shall otherwise be subject to the same payment terms and requirements (other than those relating to the calculation thereof) as the incentive component of the Management Services Fee under the OSA, and shall be implemented as an increase or decrease (as applicable) of such incentive component of the Management Services Fee payable to the Service Provider on an annual basis.

Repayment Upon Termination:	In the event of termination of the OSA pursuant to Section 8.2, 8.4 or 8.5 of the OSA, in addition to any amounts otherwise payable by LIPA to the Servicer Provider under the OSA, the Service Provider shall be entitled to repayment from LIPA of the discounted cash flows associated with the aggregate Capital Expenditures made by the Service Provider that remains unreimbursed by LIPA at the time of the termination of the OSA.
Three Year Rate Plan:	The Service Provider and LIPA shall agree upon the Utility 2.0 Capital Budget and include it in each of the preliminary Consolidated LIPA Budget to be prepared pursuant to Section 5.2(B)(2) of the OSA, the preliminary Three Year Rate Plan to be prepared pursuant to Section 6.2(B) of the OSA, the Three Year Rate Plan to be submitted to the DPS pursuant to Section 6.2(D) of the OSA and the final Consolidated LIPA Budget to be agreed upon pursuant to Section 6.2(E) of the OSA, in each case in accordance with the requirements and processes, and subject to the obligations and dispute resolution provisions, set forth in the OSA applicable to a Capital Budget. The fixed compensation and the incentive payments from LIPA to Service Provider will commence contemporaneously with the effectiveness of the rates to be implemented in accordance with the rate case to be filed by February 1, 2015.

Performance Driven Investment Recovery Model

Illustrative Payment Schedule

Base Payment Schedule
Compensation schedule for $200 million investment for 2015 – 2018

$MMs	Total	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CapEx	(200)	(14)	(63)	(77)	(46)	-	-	-	-	-	-	-	-
Repayment	322	-	7	21	34	40	40	40	40	40	33	20	6

*Rounded numbers

Proposed Performance Multiplier

Potential incentive compensation is based on relative performance as measured by Program Administrator Cost test (“PAC”).

PAC	Multiplier
<1.1	0.9x
1.1	1.0x
1.2	1.1x
1.3	1.2x
>1.4	1.3x

Appendix C

PSEG-Long Island

"Utility 2.0" Long Range Plan

Summary of Principal Terms and Conditions

This Term Sheet is intended to provide a summary of the principal terms and conditions of a proposed amendment (the "Amendment") to the Amended and Restated Operations Services Agreement (the "OSA") between the Long Island Lighting Company d/b/a LIPA, a New York corporation ("LIPA"), and PSEG Long Island LLC (the "Service Provider"), dated December 31, 2013, to give effect to the Long Range Plan (as defined in the OSA). This Term Sheet has been prepared for discussion purposes only and does not create any legal obligation. Capitalized terms have the meanings assigned to them in the OSA unless otherwise defined.

Utility 2.0 Capital Expenditures:	Under the Long Range Plan, the Servicer Provider or its affiliate will invest an agreed amount of capital from 2014 through 2018 in targeted programmatic investments related to the "Utility 2.0" Long Range Plan, including in energy efficiency, demand response, distributed generation and related programs within the Service Area (the "Utility 2.0 Capital Expenditures").
Utility 2.0 Operating Budget:	The Utility 2.0 Capital Expenditures will be treated as operating expenditures under the OSA and will be budgeted as an expense in the Operating and Maintenance Budget ("O&M Budget") under the OSA (such portion of the O&M Budget relating to Utility 2.0 Capital Expenditures, the "Utility 2.0 Operating Budget"). As compensation for Utility 2.0 Capital Expenditures made by the Service Provider or its affiliate, LIPA shall make monthly payments pursuant to an agreed upon payment schedule ("Payment Schedule") starting with the month immediately following the month in which the Program expenditure is made but not earlier than the implementation of the rates to be put in effect pursuant to the rate case to be filed February 1, 2015. The Utility 2.0 Capital Expenditures will otherwise be treated as Pass-Through Expenditures under the OSA and subject to the same payment terms and requirements thereof, including the 3-month pre-funding requirement.
Utility 2.0 Compensation:	The Payment Schedule will be based upon: a rate equal to \$/kw-year peak demand savings and \$/kWh energy usage savings; the savings associated with the Program on a predetermined basis; and a term equal to the expected life of the

Program equipment.

To the extent that the return on Service Provider's Utility 2.0 Capital Expenditure in a Program, as determined above, exceeds [___] percent on an annual basis, such excess return amounts shall be shared between Service Provider and LIPA's retail and commercial customers. This sharing shall be appropriately reflected in the Payment Schedule.

The Utility 2.0 Compensation monthly payment amount due Service Provider, in accordance with the above, shall otherwise be subject to the same payment terms and requirements (other than those relating to the calculation thereof) as the annual fixed component of the Management Service Fee and such payments shall be added to the monthly amount payable by LIPA pursuant to Section 5.2(B)(2) of the OSA.

Cost Effectiveness Test: To be eligible for investment by Service Provider the Program must meet the Program Administrator Cost ("PAC") test.

Repayment Upon Termination: In the event of termination of the OSA pursuant to Section 8.2, 8.4 or 8.5 of the OSA, in addition to any amounts otherwise payable by LIPA to the Servicer Provider under the OSA, the Service Provider shall be entitled to repayment from LIPA of the discounted cash flows associated with the compensation that remains unreimbursed by LIPA at the time of the termination of the OSA.

Three Year Rate Plan: The Service Provider and LIPA shall agree upon the Utility 2.0 O&M Budget and include it in each of the preliminary Consolidated LIPA Budget to be prepared pursuant to Section 5.2(B)(2) of the OSA, the preliminary Three Year Rate Plan to be prepared pursuant to Section 6.2(B) of the OSA, the Three Year Rate Plan to be submitted to the DPS pursuant to Section 6.2(D) of the OSA and the final Consolidated LIPA Budget to be agreed upon pursuant to Section 6.2(E) of the OSA, in each case in accordance with the requirements and processes, and subject to the obligations and dispute resolution provisions, set forth in the OSA applicable to a O&M Budget.

The compensation payments from LIPA to Service Provider will commence contemporaneously with the effectiveness of the rates to be implemented in accordance with the rate case to be filed by February 1, 2015.

Savings Driven Investment Recovery Model

Illustrative Payment Details

Proposed Avoided Costs

Savings are calculated as the total avoided capacity and energy costs applied to deemed savings over estimated useful life of underlying equipment. Also includes the net present value of any transmission and distribution capital expense deferral, as applicable.

Year	Capacity ($/kW-yr)	Energy ($/kWh)
2015	$301.24	$0.038
2016	$303.53	$0.043
2017	$305.88	$0.046
2018	$308.31	$0.050
2019	$310.79	$0.054
2020	$313.35	$0.058
2021	$315.98	$0.060
2022	$318.69	$0.061
2023	$321.47	$0.064
2024	$324.33	$0.065
2025	$327.27	$0.067
2026	$330.29	$0.069

Note: Benchmark prices are based on a LIPA study of costs for CCGT procurement on Long Island. Prices above represent 10% discount to existing energy efficiency and renewable energy program benchmark

Proposed Shared Savings

To the extent that the implied return exceeds thresholds below, the excess return will be shared accordingly.

ROI	Customer	PSEG LI
Between 8.0% and 9.0%	50%	50%
Between 9.0% and 10.0%	80%	20%
>10.0%	100%	0%

PSEG LONG ISLAND

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